COMPTON

PETROLEUM CORPORATION

2006 ANNUAL REPORT

· GROWTH THROUGH THE DRILL BIT ·

FOCUSED ON NATURAL GAS RESOURCE PLAYS

CORPORATE PROFILE

Compton Petroleum Corporation is a Calgary based public company actively engaged in the exploration, development, and production of natural gas, natural gas liquids, and crude oil in the Western Canada Sedimentary Basin. Compton's shares are listed on the Toronto Stock Exchange under the symbol CMT and on the New York Stock Exchange under the symbol CMZ.

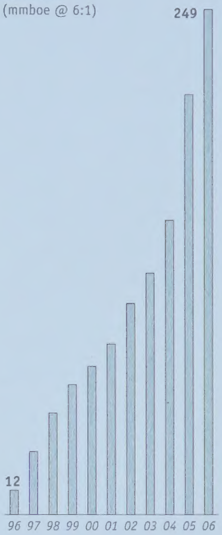
ANNUAL MEETING INFORMATION

The Annual General Meeting of Shareholders will be held on Thursday, May 10, 2007 at 3:30 p.m. in the Historical Ballroom of the Calgary Chamber of Commerce, 517 - Centre Street South, Calgary, Alberta, Canada.

Financial Highlights

($000s, except where noted)	2006	2005	2004
Total revenue	$ **533,656**	$ 557,879	$ 391,659
Cash flow from operations	$ **256,305**	$ 278,112	$ 177,131
Per share: basic ($)	$ **2.01**	$ 2.21	$ 1.51
diluted ($)	$ **1.92**	$ 2.11	$ 1.43
Net earnings	$ **127,426**	$ 81,326	$ 63,633
Per share: basic ($)	$ **1.00**	$ 0.65	$ 0.54
diluted ($)	$ **0.95**	$ 0.62	$ 0.51
Capital expenditures	$ **525,874**	$ 513,536	$ 316,401
Corporate debt, net	$ **875,548**	$ 597,656	$ 419,197
Shareholders' equity	$ **734,124**	$ 596,336	$ 424,078

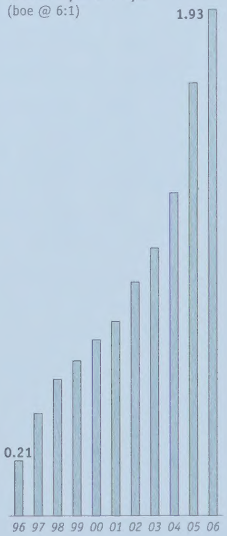
Proven + Probable Reserves (mmboe @ 6:1)



Operational Highlights

	2006	2005	2005
Average daily production volumes			
Natural gas (mmcf/d)	**142**	131	123
Liquids (light oil & ngls) (bbls/d)	**9,516**	7,646	6,330
Total oil equivalent (boe/d)	**33,187**	29,424	26,876
Average pricing			
Natural gas (per mcf)	$ **6.37**	$ 8.42	$ 6.46
Liquids ($/bbl)	$ **58.53**	$ 56.04	$ 43.21
Total oil equivalent ($/boe)	$ **44.05**	$ 51.95	$ 39.82
Field operating netback ($/boe)	$ **28.16**	$ 31.46	$ 22.86
Cash flow netback ($/boe)	$ **21.52**	$ 25.76	$ 17.60
Undeveloped land			
Gross acres	**980,179**	971,317	1,019,854
Net acres	**798,192**	738,954	729,429
Average working interest	**81%**	76%	72%
Reserves			
Proved (mboe)	**147,218**	125,960	96,805
Proved + probable (mboe)	**248,755**	206,671	144,777
Reserve life index (Proved)	**12.1**	11.7	9.9

Proven + Probable Reserves/Share O/S (boe @ 6:1)



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2006 President's Message

2006 marks Compton's tenth year of operations as a public corporation. During this time, our corporate strategy has never wavered: development of our natural gas resource plays through the drill bit. Since 1996, Compton has advanced from a high risk pure exploration company to a strong intermediate exploration and production corporation with outstanding assets. Since 1996, our reserves have grown at a compound annual growth rate of 35%. Today, Compton has approximately 1.5 Tcfe or ¼ billion boe of long life reserves, valued in excess of $3 billion dollars.

But there's more. Significant value remains to be added from a low risk, large scale drilling program across Compton's undeveloped lands. Our strategy of developing Compton through the drill bit with a low risk, repeatable drilling program promises significant potential upside for our shareholders.

Since 1996, we have grown from a company with less than 1,000 boe per day of production to an intermediate corporation currently producing approximately 33,500 boe per day. Our 2006 average production of 33,187 boe per day represents a 13% increase over last year. The asset base we have established is solid. Over time, we have assembled the technical expertise, land, and infrastructure needed to successfully grow a resource based company. Our geological models are working and from our drilling results we know the gas is present. Compton is well positioned to grow to the next level.

Since 1996, we have grown from a company with less than 1,000 boe per day of production to an intermediate corporation currently producing approximately 33,500 boe per day. Our 2006 average production of 33,187 boe per day represents a 13% increase over last year.

THE NEXT LEVEL — FUTURE OPPORTUNITIES

Compton is opportunity rich. The work we completed in 2006 and the plans we have for this year are stepping stones to a large scale drilling program in 2008 and beyond.

Unlocking the value inherent in our resource base is our first priority. In 2006, we drilled 342 wells with a 94% success rate. This drilling program delivered 42.2 million boe proved plus probable reserve adds, after production, for total proved plus probable reserves of 249 million boe as at December 31, 2006. On a per share basis, this number equates to 1.93 boe versus 1.65 boe from last year. Importantly, we achieved this growth at a highly competitive cost of $8.84 per boe, excluding future capital, or $13.56 per boe, including future capital. Given the inflationary operating environment and escalating finding and development costs that we've seen industry wide in 2006, Compton's top quartile finding and development costs are outstanding. The successful low cost development of our assets speaks to the repeatability of our resource plays.

COMPTON'S CORE AREAS — RESOURCE PLAYS

Compton's geographical presence is entirely based in Alberta. We have approximately 1.4 million net acres of largely contiguous land on which to grow our company. Our asset portfolio is comprised of four natural gas resource plays and one conventional oil play in the Peace River Arch.

SOUTHERN ALBERTA SHALLOW GAS

Plains Belly River and Edmonton Coal Bed Methane

In southern Alberta Compton holds in excess of 1,000 sections of land prospective for the Belly River and Edmonton Coal Bed Methane. We have drilled approximately 550 wells in this play to date, and with 450 of these wells currently tied-in, Belly River production has been established across all our land in this area. Compton's current Belly River production averages 45 mmcf per day. Each successful well has approximately 0.4 bcf of reserves, and an average production of 100 mcf per day after one to two years. As an example of what an increased well count can accomplish, another 500 producing

Belly River wells – all low cost and low risk additions – would easily double Compton's production in this area. We have over 1,000 square miles of 3D seismic that we will continue to use in the identification of optimal downspace drilling locations. The Alberta Energy and Utilities Board has passed legislation allowing for automatic approval of four wells per section spacing in certain areas and producing zones, and some industry competitors are already drilling six to eight wells per section. The number of wells required to develop this play is approximately 4,000, based on our current land holdings and current approved spacing. We are confident our models are repeatable. The key elements required are:

{ Large land base
{ Control and operatorship
{ Infrastructure
{ Track record – repeatability of models
{ Financial strength
{ **Control of costs**
{ **Experienced technical professionals**
{ **Resource manufacturing and processing model**
{ **Large well counts – downspacing and commingling**

Compton's 2007 objectives are to add the remaining elements, those highlighted in bold above, necessary for a large scale drilling program. We will focus on acquiring experienced staff and further reducing costs to establish a resource manufacturing and processing model in this area.

DEEP GAS — HOOKER, NITON, AND CALLUM

Compton's Deep Gas teams oversee three separate resource plays: Hooker, Callum, and Niton-Caroline. At Hooker, we drilled 18 wells in 2006 to test the outer edges of the play, and we plan to drill 20 more this year, the majority of which are on in-fill locations. Importantly, this play continues to grow in size, and we have yet to define the edges of the Hooker pool. Hooker's land base of over 200 sections is now approximately 2/3 development and 1/3 exploration. Compton's geological and engineering models show that this asset would be more efficiently developed using downspacing of up to four wells per section.

Callum is our most exploratory play. We hold 100% working interest in 110 sections where we have drilled 13 exploratory wells. Recognizing the importance of proceeding with a small footprint in this environmentally sensitive area, Compton's drilling activities here are based on one drill pad per section. In 2007, we will drill two exploratory wells at Callum, further testing our geological and completion models.

In central Alberta at Niton we drilled 31 wells last year, with results exceeding our expectations. This resource play is characterized as multi-zone, deep basin gas, and due to excellent results, we plan to drill another 39 wells here in 2007. As with all of our deep basin plays, downspacing will assist with optimizing our Niton play.

PEACE RIVER ARCH — CONVENTIONAL LIGHT OIL

Compton's conventional oil play in the Peace River Arch has been very successful. In a few short years, we have quickly developed this area to approximately 7,000 boe per day. 2007 objectives are to accelerate horizontal drilling in this area, define the pool edges, and determine waterflood potential and economic value add. As a steady cash flow source or a potential disposition, this light oil play will materially contribute to the accelerated development of Compton's resource plays.

Compton's definition of a resource play:

{ *Repeatable with predictable results*
{ *Reservoir extends over a large area*
{ *Basically water free reservoir*
{ *Unconventional gas (under or over pressured)*
{ *Significant vertical column of gas resulting in large gas in place*

Any one of Compton's resource plays holds the potential to double our year end 2006 reserve report.

2007

The current year represents an important juncture for Compton. This year to date, the oil and gas industry has encountered higher than normal natural gas storage levels, a continued high operating cost environment, lower commodity prices, and significant capital cutbacks by producers. Our plans for 2007 have been developed giving full consideration to existing industry and market conditions. Capital discipline and efficiency are foremost in Compton's strategy as we put all of the necessary elements in place to move Compton to the next level. We will add key people to our existing technical and management teams. We will look closely at operating costs, continually searching for ways to bring them down, and we will drill efficiently, taking full advantage of the new downspacing and commingling regulatory pronouncements. In short, we are setting the stage for an aggressive, large scale 2008 drilling program, one that is repeatable and predictable, sustainable and profitable – a resource manufacturing and processing model.

Ernie Sapieha
President & Chief Executive Officer

The primary objective for 2007 is clear: continue to develop our resource properties while setting the stage for 2008 and beyond. We have developed a conservative budget for 2007, with planned spending of approximately $375 million. We intend to drill 330 wells, and cash flow is expected to be in the range of $310 to $320 million.

Compton is well positioned for continued growth. We have a solid understanding of our industry and where it is headed in the future. We have adopted a strategy for both the short and long term, one that will continue to create value for our shareholders.

2006 was a challenging year for the energy industry, perhaps one of the most volatile and difficult I have encountered. Despite the tough industry conditions in 2006, Compton again demonstrated the ability to add significant, low cost reserves and shareholder value through the drill bit for the tenth year in a row. I was sincerely impressed by the efforts and commitments of everyone involved with Compton. I would like to thank all of Compton's employees and our Board of Directors for their strong support and enthusiasm.

Sincerely,

ERNIE SAPIEHA
President & Chief Executive Officer

March 23, 2007

Review of Operations

Property Review

Compton engages in oil and gas exploration and development in the Western Canada Sedimentary Basin of Alberta, Canada. Our focus is on the Deep Basin portion of the Sedimentary Basin, which extends from Northwest Alberta and British Columbia to the United States border. In this large geographical region, we pursue two types of resource plays. A shallow gas resource play, targeting the Plains Belly River and overlying Edmonton Horseshoe Canyon zones, and the three deep gas resource plays that include the Basal Quartz sands at Hooker, the stacked, thrusted Foothills Upper Cretaceous Belly River play at Callum in the south, and the Gething/Rock Creek sands at Niton in central Alberta. Compton's third core area, located in the Peace River Arch, is comprised of two conventional oil properties at Worsley and Cecil.

Our Shallow Gas Operations

SHALLOW GAS

The Plains Belly River and overlying Edmonton Horseshoe Canyon shallow gas zones cover more than 1,000 sections of Compton held land in southern Alberta. The entire 800 metre gas-charged section is comprised of multiple Belly River sands, silts, shales, and coals, overlain by the Edmonton/Horseshoe Canyon Coals that similarly include, sands, silts, and shales. In 2006 we drilled 183 wells through the Edmonton Horseshoe Canyon Group targeting the Belly River section, for a total of 550 wells drilled as of year end. This allows for numerous recompletion and commingling opportunities. Going forward, we will focus on downspacing, development drilling, and recompletions in order to establish a resource manufacturing and processing model designed to maximize production. Three key elements – one industry driven, the others Compton driven -- have recently come together to make this model possible.

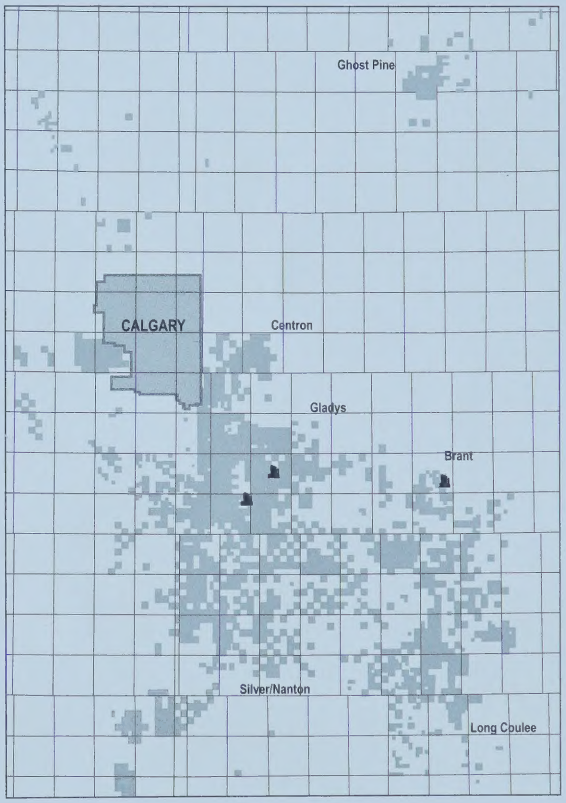
1. In July 2006, the Alberta Energy and Utilities Board ("EUB") announced a downspacing initiative for zones above the Mannville, including the Plains Belly River, that is intended to see standard well spacing increase from one to four wells per section. Reduced spacing is critical in the development of our unconventional reservoirs that require greater well density for more efficient resource development and recognition. With our current land holdings, this new regulation adds over 4,000 locations to our drilling inventory. Additional to downspacing, we now have the ability to maximize production through commingling Belly River with the Edmonton/Horseshoe Canyon zones. The EUB released a directive for commingling on October 31, 2006 that allows for concurrent production of Belly River and Edmonton/Horseshoe Canyon Coals as a single procedure, following minimal application.

2. We are in a unique position of having a large 3D seismic data base, totaling 2,140 km^2 (826 mi^2) as at December 31, 2006, with an additional 427 km^2(165 mi^2) as of the first quarter of 2007. The use of 3D seismic is key in positioning downspace well locations that maximize production and reduce capital requirements.

3. In recent years, we have focused efforts on establishing and expanding infrastructure and facilities in our core areas. We currently have 466 km of low pressure pipelines. Years in the making, this intricate system of compressors and low pressure pipeline gathering systems covers a large portion of our existing land base.

2006 saw Compton take advantage of new EUB downspacing and commingling initiatives to successfully test our seismic modeling and complete infrastructure development. In 2006 we drilled 25 sections to as many as four wells per section. Preliminary results on the second to fourth wells in each section have generally exceeded the first drill in the section. As a result, we will ramp up our Belly River/Edmonton drilling program in 2007 to grow production from these zones. Late in the fourth quarter of 2006, we tied in 21 Belly River/Coalbed Methane wells. An additional 21 wells are projected to be tied in during the first and second quarters of 2007.

In 2006 we expanded our southern Alberta shallow gas compression capability to 105 mmcf/d.



In 2007, we have budgeted 215 shallow gas wells targeting the Plains Belly River/Edmonton group. In select areas, drilling is planned in groups of 20 to 40 wells to capitalize on downspacing and associated cost efficiencies. As well, we have 69 hybrid coal bed methane and sand gas wells. Low pressure gathering and compression facilities are largely in place in the area to assist in reducing on-stream times. It is our intent that production from these multi-zone wells will be commingled for optimal production results. Going forward, in 2008 and beyond, we plan to accelerate drilling and associated production through large well counts plus tie-ins to existing facilities. A 4,000 well drilling inventory makes this possible.

Our Deep Gas Operations

DEEP GAS

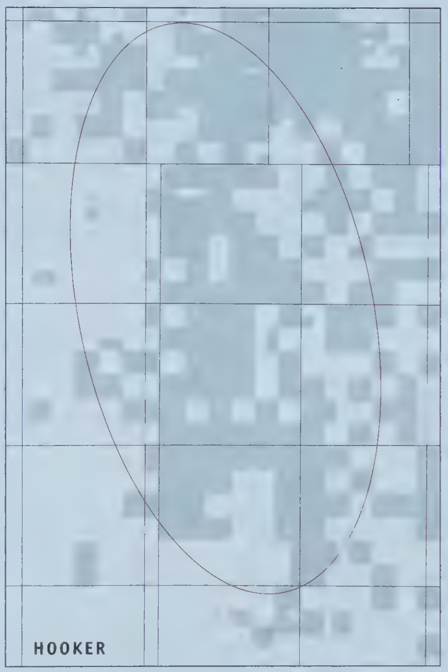
Compton has three deep gas resource plays: the Basal Quartz sands at Hooker, the stacked, thrusted, Belly River play at Callum in southern Alberta, and the Gething/Rock Creek sands at Niton in central Alberta.

HOOKER

Discovered by Compton in 1999, the Basal Quartz sandstone pool at Hooker is the southern Alberta extension of the Lower Cretaceous Deep Basin gas trend. This play covers an extensive area of approximately 124,800 net acres, with our working interest averaging 85%. Current production extends over five townships, and in 2006, we drilled 18 wells at Hooker, testing the aerial extent of the play. The edges of the Hooker pool have yet to be defined.

In 2006, the total Hooker infrastructure system was expanded to 65 mmcf/d.

The key to maximizing production at Hooker, or any Deep Basin play, is downspacing. Currently, Compton's drilling is approved for two wells per section, although the majority of the 120 gas wells drilled to date in this area are on single section spacing. Our engineering and geological models indicate that a minimum four wells per section is required for optimal production here. As such, we have made an application to the EUB to downspace on a pilot basis, with two other sections pending. We will be drilling approximately 20 Basal Quartz wells during 2007. The majority of these wells are infill locations planned for the second half of 2007, once downspacing is approved.



CALLUM

Our Callum property consists of a series of overpressured, thrusted low permeability Belly River sands in the foothills of southern Alberta. With the acquisition of our partner's interest in 2006, we now hold a 100% interest in 70,400 acres (110 sections) of land on trend. A total of 13 exploratory wells have been drilled over the life of the play. Based on our initial detailed geological, geophysical, and engineering analysis of seismic, cores, well logs, test and production data, Callum appears to exhibit many similarities to the deep unconventional gas pools of the Rocky Mountain region of the United States.

In 2006, we drilled five exploratory wells, all of which encountered multiple sands. The wells were cased and extensively cored. The two most recent wells, drilled during the third quarter of 2006, are two and 15 miles south of current production, respectively, and following laboratory analysis of the cores, these wells will be appropriately completed.

Compton is conducting environmental studies on four additional pads prior to submitting the required license applications. We are working with all stakeholders in the area to proceed in an environmentally responsible manner and we remain committed to minimizing the impact of our activities. To this end, drilling in this area is based on one drill pad per section.

In 2007, we plan to drill two exploratory wells at Callum. We remain confident in pursuing this challenging and technically complex play. Our activities in the area will increase once regulatory well licensing issues are resolved.

NITON

The Niton area in central Alberta, 150 miles west of Edmonton, is in the Alberta Deep Basin. Our main targets are the Jurassic Rock Creek and Cretaceous Gething, analogous to the Hooker pool in southern Alberta. Proprietary exploration, development, and operations knowledge gained in southern Alberta has resulted in accelerated growth of this core area.

We have assembled 156,800 (128,000 net) acres of land in this multi-target area. In 2006, 31 wells were drilled with results exceeding expectations.

Compton undertook a major facility project at Niton during 2006. At our McLeod River 7-34-54-14W5 gas plant all major equipment was purchased in 2006 to prepare for a March 31, 2007 completed gas plant expansion from 18 to 23 mmscf/d processing capacity.

Conventional Oil Operations

WORSLEY/CECIL

Located in the Peace River Arch, the Worsley and Cecil properties produce from the Triassic Charlie Lake Formation, a layered sandy Carbonate. These two properties comprise the majority of Compton's conventional oil production.

For 2006 the Worsley pool was the focus of the Company's operations in this area. We drilled 27 Charlie Lake oil wells in 2006, for a total of 118 vertical and 12 horizontal wells in the area.

The horizontal drilling program at Worsley has produced very positive results. One horizontal well replaces three vertical wells, at a cost saving of $1.2 million. Horizontal wells allow successful drilling and production in oil bearing rock layers where underlying water is recognized.

In 2005, the Company initiated a waterflood program in this area that is projected to increase the ultimate recovery factor for the pool to 25% from 15% on primary depletion. A total of eight wells have been converted to injectors.

The Worsley gas plant was successfully expanded with the installation of a 15 mmcf/d amine unit in the first quarter of 2007. The plant is now capable of processing 13 mmcf/d.

2007 will focus on horizontal drilling and definition of pool boundaries.

Operating Results

UNDEVELOPED LAND

In 2006, we continued to maintain a dominant land position in our core areas. The Company's total net land inventory increased 12% in 2006, with acquisitions occurring primarily in the southern and central Alberta core areas. Net undeveloped land increased 8% from the prior year. For 2006 we had an 81% average working interest in our undeveloped land base, as opposed to 76% in 2005, reflecting Compton's strategy to establish high ownership levels and control of operations.

LAND SUMMARY

	Undeveloped Acres		Total Acres	
Area	Gross	Net	Gross	Net
Southern Alberta	495,854	473,444	907,134	822,966
Central Alberta	284,603	206,617	581,016	340,254
Peace River Arch	102,400	71,775	196,960	119,188
Northern Alberta	41,888	15,572	68,769	23,207
Other	55,434	30,784	84,984	33,866
December 31, 2006 total	**980,179**	**798,192**	**1,838,863**	**1,339,481**
December 31, 2005 total	971,317	738,954	1,709,982	1,195,792

During 2007, we plan to continue to invest in the future and expand in our core areas. Our 2007 budget includes $39 million directed towards land acquisitions and seismic surveys in our major operating areas.

DRILLING ACTIVITY

We drilled 342 gross (274 net) wells in 2006 with a 94% success rate, compared with 392 gross (334 net) wells drilled in 2005.

Of the 342 wells drilled in 2006, 84% were classified as development wells and 16% were classified as exploratory wells, compared to 80% and 20% respectively in 2005. The higher percentage of development wells in the current year reflects the increasing success of our oil and gas plays.

DRILLING SUMMARY

Years ended December 31,	Natural Gas	Oil	D&A	Total	Net	Success
Southern Alberta	184	1	4	189	167	98%
Central Alberta	56	9	5	70	47	93%
Peace River Arch	11	46	11	68	46	84%
	251	56	20	327	260	94%
Standing, cased wells				15	14	
2006 Total				**342**	**274**	
2005 Total	261	114	17	392	334	

RESERVES

For the year ended December 31, 2006, Netherland, Sewell & Associates, Inc. ("NSAI") independently evaluated 94% of Compton's reserves and audited the Company's internal evaluation of the remaining 6%.

As required by National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"), Compton filed Form 51-101 F1 as part of our Annual Information Form ("AIF"). The AIF is considered comprehensive. Certain

information has been summarized below regarding our operations. All such information is consistent with the Form NI 51-101 F1 filing. Compton's extended disclosure contained in the AIF is available on both the SEDAR website and our website.

In December 2006, Compton entered into agreements for the sale of two minor, non-core properties that generated net proceeds of $45.9 million, all of which were received in the first quarter of 2007. The effective dates of these sales were as of year end. Accordingly, we excluded these properties from the December 31, 2006 reserve report and the calculation of finding, development, and acquisition costs. The impact of these sales on corporate indebtedness as at December 31, 2006 is set out in the Liquidity and Capital Resource section of Management's Discussion and Analysis in this Annual Report.

SUMMARY OF ESTIMATED RESERVE VOLUMES – FORECAST PRICES AND COSTS (1)

	Crude Oil		**Natural Gas**		**NGLs**		**Sulphur**		**Total**	
As at December 31, 2006	Gross (Mbbl)	Net (Mbbl)	Gross (Bcf)	Net (Bcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mlt)	Net (Mlt)	Gross (Mboe)	Net (Mboe)
Proved										
Developed producing	15,065	13,985	443	362	8,021	5,734	1,392	1,237	98,337	81,302
Developed non-producing	1,714	1,592	69	57	1,152	795	50	40	14,364	11,893
Undeveloped	3,220	2,752	175	146	2,016	1,473	115	96	34,517	28,693
Total proved	19,999	18,329	687	565	11,189	8,002	1,557	1,373	147,218	121,888
Probable	9,234	7,884	502	419	7,879	5,759	714	603	101,537	84,007
Total proved plus probable	**29,233**	**26,213**	**1,189**	**984**	**19,068**	**13,761**	**2,271**	**1,975**	**248,755**	**205,895**
2005 total proved plus probable	28,493	25,488	954	788	16,628	12,070	2,545	2,221	206,672	171,031

(1) Numbers may not add due to rounding.

In 2006, we added 42.2 MMboe, after production, to our proved plus probable reserves primarily through the drill bit. Total proved plus probable reserves increased 20% from the prior year to 249 MMboe.

Our total proved reserve base is comprised of 78% natural gas and 22% liquids. Proved producing reserves comprise 67% of total proved reserves, while total proved reserves account for 59% of the proved plus probable reserves. We have a 12 year proved reserve life index.

NET PRESENT VALUE OF RESERVES – FORECAST PRICES AND COSTS (1)

($millions)	Future net revenue before income taxes (1) discounted at a rate of 0%	8%	10%
Proved			
Producing	$ 2,774	$ 1,446	$ 1,302
Non-producing	546	274	242
Undeveloped	1,072	438	363
Total proved	$ 4,392	$ 2,158	$ 1,907
Probable	3,241	1,154	938
Total proved plus probable	**$ 7,633**	**$ 3,312**	**$ 2,845**
2005 proved plus probable	$ 6,199	$ 2,842	$ 2,493

(1) Pricing assumptions are the average of four major Canadian oil and gas evaluation firms. Numbers may not add due to rounding.

Future net revenues are calculated based upon estimated revenue less royalties, operating costs, future development costs, and well abandonment costs. Estimated income taxes have not been deducted. The net present value should not be considered the current market value of our reserves or the costs that would be incurred to obtain equivalent reserves.

RESERVE RECONCILIATION (NET AFTER ROYALTIES) – FORECAST PRICES AND COSTS

	Crude Oil, NGLs, and Sulphur			**Natural Gas**		
	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)
December 31, 2005	28,731	11,047	39,778	449,790	337,719	787,509
Extensions	916	1,033	1,949	27,309	20,086	47,395
Improved recovery	1,027	1,069	2,096	50,394	125,247	175,641
Technical revisions	(667)	620	(47)	75,206	(84,481)	(9,275)
Discoveries	317	54	371	4,312	4,441	8,753
Acquisitions	222	437	659	11,331	16,982	28,313
Dispositions	(229)	(14)	(243)	(12,939)	(1,426)	(14,365)
Production	(2,613)	–	(2,613)	(40,300)	–	(40,300)
December 31, 2006	**27,704**	**14,246**	**41,950**	**565,102**	**418,568**	**983,671**

D. FINDING & DEVELOPMENT COSTS

Our 2006 reserve report was reduced by property sales that closed subsequent to year end. Accordingly, Finding, Development and Acquisition ("FD&A") costs have been calculated giving effect to the net proceeds realized on the dispositions. It should be noted that the aggregate of the exploration and development costs incurred in 2006 and the change during the year in estimated future development costs, generally will not reflect total F&D costs related to reserves additions for the year.

FD&A COSTS

($/boe)	**2006**	2005	2004	3 Year Average
Including future capital				
Proved	**$ 18.45**	$ 15.42	$ 14.91	$ 16.37
Proved plus probable	**$ 13.56**	$ 13.02	$ 13.19	$ 13.19
Excluding future capital				
Proved	**$ 14.36**	$ 12.84	$ 13.87	$ 13.61
Proved plus probable	**$ 8.84**	$ 7.05	$ 8.51	$ 7.97

DESPITE THE TOUGH INDUSTRY CONDITIONS IN 2006, THE COMPTON TEAM AGAIN DEMONSTRATED ITS ABILITY TO ADD SIGNIFICANT, LOW COST RESERVES AND SHAREHOLDER VALUE THROUGH THE DRILL BIT FOR THE TENTH YEAR IN A ROW.

WE TRULY APPRECIATE THE EFFORTS AND COMMITMENTS OF EVERYONE INVOLVED WITH COMPTON AND WOULD LIKE TO THANK ALL EMPLOYEES AND OUR BOARD OF DIRECTORS FOR THEIR STRONG SUPPORT AND ENTHUSIASM.

THE MOST IMPORTANT PART OF ANY BUSINESS IS CREATIVE PEOPLE WITH GREAT IDEAS COMBINED WITH PASSION, DEDICATION, AND ENTHUSIASM.

[illegible]

Robert Dion,
[illegible]

Gary Follensbee,
Manager, Mazeppa Operations

George Fukushima,
Manager, Reserves

[illegible]

Richard Jay,
[illegible]

Marc Junghans,
VP Exploration

John Kendrick,
Manager, Environment, Health & Safety

Norm Knecht,
VP Finance & C.F.O.

Theresa Kosek,
Accounting Manager

ONE OF COMPTON'S GREATEST STRENGTHS HAS ALWAYS BEEN OUR INNOVATIVE PEOPLE AND THE COMPTON CULTURE THEY HAVE CREATED. MORE THAN EVER, OUR SKILLED AND DEDICATED TEAMS ARE CRUCIAL TO THE SUCCESS OF THE COMPANY.

Bill Leonard,
Manager, Human Resources

Derek Longfield,
VP Special Projects

Bill McCloskey,
Manager, Exploration South

Garry McCullough,
Land Manager

Tim Millar,
VP, General Counsel & Corporate Secretary

Wade Mrochuk,
Production Manager

Paul Parzen,
Manager, IT, Risk & Internal Audit

Murray Stodalka,
VP Operations & Engineering

Pary Weiler,
Manager, Surface Land

Bob Wilson,
Manager, Engineering North

Responsible Corporate Citizenship

Hockey photo courtesy of the Western Wheel

Corporate Citizenship

Compton recognizes the importance of and positive impact that results from responsible corporate citizenship. We are committed to behaving ethically and contributing to economic development while improving the quality of life for our employees, their families, and the local community. We believe in giving back to the communities in which we operate and, to this end, we have supported numerous local initiatives throughout 2006.

EDUCATIONAL PARTNERSHIPS

For the past six years, Compton has formed a Corporate/Educational Partnership with a Calgary Board of Education Public School. During the 2005-2006 school year, Compton partnered with two schools: Falconridge Elementary School in Calgary and Spitzee Elementary School in High River. Each partnership supported a variety of school initiatives as identified by the school's staff, parents, and students. Sandra Levesque, Principal of Falconridge Elementary, said, "Your contribution in providing our school with both the gifts of funds and time has made a significant impact upon our school."

We also support our partner schools with Compton's Student Ambassador Program, which sponsored three university students to work with the students and staff at Falconridge during May and June of 2006. Principal Levesque commented on the work of these students saying, "Compton can be very proud of having selected these wonderful students to represent their organization, giving them the opportunity to demonstrate their commitment to education."

Compton has formed two Educational Partnerships for the 2006-2007 school year. These partnerships will once again focus on enabling and assisting the staff at each school as they work to enhance the quality of educational opportunities and experiences for the students at Buchanan Elementary School in Calgary and Ecole Joe Clark School in High River.

COMMUNITY PARTICIPATION

Compton's Corporate Sponsorship and Donation Programs contribute to charities and community endeavors that enhance the quality of life in the areas where we are active. In 2006, we made contributions to well over a hundred not-for-profit organizations, athletic teams, schools, and community-based organizations in areas such as Black Diamond, Calgary, Drayton Valley, and Nanton, to name only a few. Compton is committed to assisting in the betterment of the communities in which we operate.

YMCA Calgary

CALGARY INTERNATIONAL CHILDREN'S FESTIVAL

OKOTOKS AGRICULTURAL SOCIETY

Oilfields/Okotoks Health Foundation

Environment, Health and Safety

The Human Resources, Compensation, Environmental, Health and Safety Committee of the Board of Directors undertakes, with Management, all of the necessary procedures, policies, and industry practices designed to protect our employees and contractors, as well as members of the public and the environment. In an effort to identify opportunities to improve environmental, health and safety ("EH&S") performance, operations at both the corporate and field level are regularly assessed. We are committed to responsible resource development. By meeting or surpassing all applicable regulatory requirements, education, and training of personnel on EH&S polices and procedures, and following industry best practices, we believe our operations are safer for employees, community residents, and stakeholders, in addition to providing minimal environmental impact.

We believe in a long term commitment to environmental responsibility and to protecting environmental quality. Protection of the environment is paramount to both the success and reputation of the Company, and, as such, we strive to minimize our environmental footprint in all areas of operation, both initially and throughout the life of the operations of the well or facility. This commitment is demonstrated through:

- Site inspections and assessments to ensure compliance with environmental regulatory legislation and standards;
- Participation in industry programs that benchmark and measure our performance with that of our industry peers;
- Evaluation of the environmental impact of all new projects;
- Effective project planning and implementation, reduction of emissions, waste minimization, and energy conservation;
- Sharing best practices through networking with peer associations; and
- Implementation of internal, strategic management programs.

Health and safety management is a fundamental value of the executive leadership team, management, and employees of Compton. We are committed both to carrying out our operations in a safe and responsible manner and to being an industry leader in health and safety practices. All employees, contractors, and subcontractors are required to be familiar with and adhere to Compton's safety policies and procedures, regulatory legislation, industry guidelines, and best practices. We have not experienced an employee lost time accident since January 2001, and we continue to be well below industry average in employee total recordable injury ratio, contractor lost time ratio, and contractor total recordable injury ratio.

In 2006 Compton received the "Work Safe Alberta 2005 Best Safety Performer Award" jointly issued by Alberta Human Resources and Employment and the Occupational Health and Safety Council. This distinction was granted to the top 350 of 128,000 Alberta employers for exceptional performance in workplace health and safety, affirming Compton's exceptional safety standards.

We are committed to the continuous improvement of our health and safety practices. The Company undertakes initiatives such as:

- Annual safety audits to ensure our facilities continually meet or exceed regulatory standards;
- Hazards assessments of our work sites and operations;
- Management systems in place which measure and review EHS objectives and targets set in industry recognized categories, such as lost time accidents, days away from work, and total recordable injuries;
- Quarterly reporting of our Health, Safety and Environmental practices to Compton's Human Resources, Compensation, Environmental, Health and Safety Committee of the Board of Directors, and such reporting is certified by the President and the Vice President of Operations and Engineering;
- Effective emergency response plan development, in addition to conducting routine training and testing;
- Maintaining an industry recognized safety program;
- Participation in the "Safety Stand Down" program providing an opportunity for members of the Board of Directors, Executive, employees, and contractors to meet at the field level to discuss safety and environmental issues;
- Diligent tracking and investigation on all safety and environmental incidents and near misses.

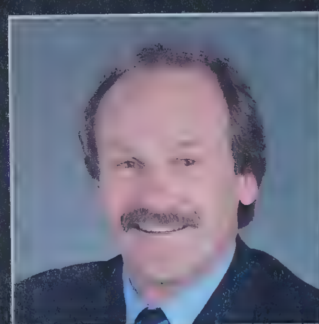
M.F. Belich

I.J. Koop

J.W. Preston

J.T. Smith

J.A. Thomson



E.G. Sapieha

Upholding the Highest Standards

Corporate Governance

Compton's Board of Directors believes adopting and upholding the highest standards of corporate governance is critical for building stakeholder confidence and for the overall success of the Company. Sound corporate governance ensures transparency and accountability for our objectives, strategy, controls, and overall performance. The Corporate Governance Committee and Board of Directors continuously monitor applicable legislation and respond appropriately to ensure the Company's compliance.

We continually adjust our practices to reflect the requirements of the New York Stock Exchange ("NYSE") Listing Standards, the Sarbanes-Oxley Act of 2002, and other current governance issues. We have adopted a Majority Voting policy for the election of our Board of Directors as part of our overall commitment to best practices in governance.

The Canadian Securities Administrators approved National Policy 58-201, "Corporate Governance Guidelines" (the "Best Practices Policy") and National Instrument 58-101, "Disclosure of Corporate Governance Practices" (the "Disclosure Instrument,") in 2005. The Best Practices Policy provides guidance on corporate governance practices, following U.S. initiatives under the Sarbanes-Oxley Act and newly adopted corporate governance rules of the NYSE and NASDAQ. The Disclosure Instrument specifically requires issuers to make certain corporate governance related disclosures. The disclosures required under the Disclosure Instrument generally correspond to the guidance in the Best Practices Policy.

A description of our corporate governance disclosures, as required by the Disclosure Instrument, is set forth in our Management Proxy Circular, which may be found on our website at www.comptonpetroleum.com.

Compton's common shares commenced trading on the NYSE on December 6, 2005. The Company is classified as a foreign private issuer in the United States by the Securities Exchange Act of 1934 (the "Exchange Act") and is therefore permitted to follow Canadian corporate governance regulations, except for:

- audit committee member independence requirements under Rule 10A-3 of the Exchange Act;
- the requirement to disclose any significant differences between the Company's corporate governance practices and those followed by domestic companies under the NYSE listing standards; and
- the requirement for the Company to submit an Annual Written Affirmation to the NYSE, confirming our compliance with the audit committee independence requirements of Rule 10A-3 and that we have provided a statement of significant corporate governance differences, and to notify in writing the NYSE if any Officer becomes aware of a material non-compliance.

Our audit committee members are independent under Rule 10A-3 of the Exchange Act. Our corporate governance practices do not differ significantly from those followed by domestic U.S. companies under NYSE listing standards, with the exceptions that (i) we do not have an internal audit function and (ii) the CEO's compensation is finally approved by the Board of Directors on the recommendation of the Human Resources, Compensation, Environmental, Health and Safety Committee. We have filed our Annual Written Affirmation with the NYSE.

3. BOARD OF DIRECTORS AND BOAR

A. BOARD MANDATE AND COMPOSITION

The Board of Directors (the "Board") has explicitly assumed responsibility for the stewardship of the Company. The Board shall operate by delegating certain of its authorities to Management, including the day to day conduct of the business of the Company and overseeing the activities of Management, while reserving certain powers for itself. The Board's fundamental objectives are to enhance and preserve long term shareholder value, to provide stewardship in order that the Company meets its obligations on an ongoing basis, and to operate in a reliable and safe manner.

The written Charter of the Board explicitly acknowledges responsibility for the stewardship of the Company and requires the Board to determine that:

- the Company has established long term goals and a strategic planning process;
- the principal risks of the Company's business are identified and appropriate systems are implemented to manage those risks;
- there is sufficient succession planning including appointing, training, managing, and monitoring Management;
- the Company has a communications policy;
- the Company's internal controls and management information systems have sufficient integrity; and
- the Company's approach to governance issues and the implementation of principles for the management of corporate governance fosters a culture of integrity throughout the Company.

Based upon applicable Canadian and U.S. securities laws and the NYSE corporate governance rules, we have adopted "Standards of Independence," which may be viewed in full on our website. The Board must affirmatively determine on an annual basis, whether or not its members are independent. Five out of six Directors, including the Chairman of the Board, have been determined to be independent. Mr. Sapieha is a non-independent Director because of his position as President & CEO of the Company.

A full copy of the Charter for the Board of Directors can be found on our website at www.comptonpetroleum.com.

B. COMMITTEES OF THE BOARD

Subject to applicable law, the Board may delegate its powers, duties, and responsibilities to Committees of the Board. In this regard, the Board has established four standing Committees, the (i) Human Resources, Compensation, Environmental, Health and Safety Committee; (ii) Audit, Finance and Risk Committee; (iii) Engineering, Reserves and Operations Committee; and (iv) Corporate Governance Committee. The mandate of each committee is reviewed annually and is summarized below. All Committees are composed exclusively of independent Directors.

i) Human Resources, Compensation, Environmental

Chairman: Irvine Koop

Members: Mel Belich, John Preston, Jeff Smith

The Committee's mandate is to assist the Board in fulfilling its oversight responsibilities with respect to human resources and compensation. Additionally, the Committee monitors the environmental, health, and safety practices and procedures of the Company for compliance with applicable legislation, conformity with industry standards, and prevention or mitigation of loss.

The Committee also has the responsibility to:

- review and oversee human resources policies of the Company;
- review succession plans for key Management positions within the Company;
- develop performance objectives for the CEO and other Officers and assess their performance against such objectives;
- recommend to the Board, salary and other remuneration for Officers of the Company. The Committee also monitors performance objectives for Officers in order that they are aligned with shareholders' interests and corporate goals;
- recommend to the Board, compensation matters, including long and short term incentives such as bonuses, stock option plans, and other benefits;
- review and recommend compensation for Board and Committee service.

The Committee fulfils its environmental, health, and safety responsibilities by:

- overseeing the Company's policies and guidelines with respect to environmental, health, and safety matters regarding the Company's facilities and operations;
- undertaking with management those policies, guidelines, practices, and procedures designed to manage risk and assume compliance with all workplace, environmental, health, and safety laws;
- reviewing and monitoring the Company's policies, procedures, and practices relating to the documentation and reporting of environmental, health, and safety regulatory approvals, compliance, and incidents; and
- generally, reviewing the Company's performance related to environment, health, and safety and confirming with management that long range preventative programs are in place.

The full Human Resources, Compensation, Environmental, Health and Safety Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

n. Jeff Smith

The Audit, Finance and Risk Committee is mandated to oversee that Management is responsible for creating and maintaining an effective risk management and internal control framework. This framework provides reasonable assurance that the financial, operational, and regulatory objectives of the Company are achieved and that the statutory responsibilities of Board are discharged.

The Committee fulfills its role on behalf of the Board by overseeing:

- the review, disclosure, and integrity of the Company's financial statements, Management's Discussion and Analysis of financial conditions and results of operations, and other financial information;
- the external auditor's qualifications, independence, and performance;
- the Company's compliance with legal and regulatory requirements;
- risk management, management information systems, governmental legislation, and external business of the Company;
- the effectiveness and integrity of the Company's system of disclosure controls and internal controls; and
- reviewing the appointments of the Chief Financial Officer and other key financial executives.

The Committee oversees the operation of an anonymous and confidential toll free telephone number and website for employees, contractors, and others to call with respect to accounting irregularities or ethical violations. The Committee has also established a procedure for the receipt, retention, treatment, and regular review of any such reported activities. This telephone number is 1-800-661-9675 and the confidential website address is www.compton-eweb.com.

The full Audit, Finance and Risk Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

iii) Engineering, Reserves and Opera [illegible]

Chairman: Jeff Smith

Members: Mel Belich, Irvine Ko [illegible]

The Committee's mandate is to review and make recommendations to the Board on the Company's engineering and reserves policies.

The Committee fulfills its oversight role on behalf of the Board and is responsible for:

- the Company's overall policies and guidelines with respect to engineering, reserves, and operations;
- undertaking with Management all necessary procedures and policies to comply with regulations and guidelines applicable to the Company and enunciated by the applicable regulatory authorities including providing assistance to Management in compliance with National Instrument 51-101, preparation of the Statement of Reserves (Form 51-101 F1), Evaluator's Report (Form 51-101 F2), and Management Report (Form NI 51-101 F3);
- meeting with the Company's Vice President of Operations & Engineering, other senior reserves personnel, and the independent reserves evaluator to review and consider the Company's reserves; and
- reviewing, assisting, and making recommendations to the Board in respect of the annual appointment of the Company's independent qualified reserves evaluators.

The full Engineering, Reserves and Operations Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

iv) Corporate Governance Committee

Chairman: Mel Belich

Members: Irvine Koop, John Pres [illegible]

The Corporate Governance Committee is responsible for developing the Company's approach to governance issues and to assist the Board in fulfilling its oversight responsibilities with respect to the development and implementation of corporate governance. The Committee functions with a view to fostering a culture of integrity within the Company.

The Committee fulfills its oversight role on behalf of the Board and is responsible to:

- recommend initiatives to maintain high standards of corporate governance;
- assess the effectiveness and performance of the Board as a whole, the Chairman of the Board, Board Committees, Committee Chairs, and individual Directors;
- define and monitor the relationship, roles, and authority of the Board and Management;
- review and evaluate corporate communication policies and practices; and
- monitor compliance with the Code of Business Conduct and Ethics.

The Committee also has the responsibility to:

- identify nominees for the Board and its Committees;
- evaluate the competencies and skills necessary for the Board as a whole to possess, the competencies and skills that existing Directors possess, and the competencies and skills each new nominee will bring to the Board;
- propose nominees for re-election as Directors by the shareholders at the annual meeting; and
- propose candidates for appointment to senior Management, Executive, and Officer positions.

The full Corporate Governance Committee Charter may be found on Compton's website at www.comptonpetroleum.com.

Compton's Code of Business Conduct and Ethics (the "Code") holds our Directors, Officers, employees, and consultants to high standards of legal and moral conduct in all areas of operations. In addition to meeting legal and regulatory requirements, we strive to conduct all operations fairly and with integrity.

The Board encourages and promotes a culture of ethical business conduct through its guidance provided to Officers and senior members of Management and its oversight of the operations of the Company. Additionally, the Whistle Blower Policy (the "Policy") adopted by the Company promotes a culture of openness, honestly, and accountability. The Policy establishes procedures for the receipt, retention, treatment, and regular review of any unlawful activities, accounting irregularities or ethical violations.

The Board monitors compliance with the Code through the use of an Ethics Hotline, which is an anonymous and confidential toll free telephone number. Additionally, any violations of the Code brought to the attention of Management are reported to the Board. No waivers from the Code were granted to the Company's Directors, Officer, employees, or consultants in 2006.

Compton's Code of Business Conduct and Ethics and Whistle Blower Policy may be viewed on our website at www.comptonpetroleum.com.

Management's Discussion and Analysis

ADVISORIES

Management's Discussion and Analysis ("MD&A") is intended to provide both an historical and prospective view of our activities. The MD&A was prepared as at March 23, 2007, and should be read in conjunction with the audited consolidated financial statements and related notes for the year ended December 31, 2006. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation to U.S. GAAP is included in Note 20 to the consolidated financial statements.

Additional advisories with respect to forward looking statements, the use of Non-GAAP Financial Measures, and the use of BOE volumetric measures are set out at the end of this MD&A.

Corporate Overview & Strategy

Compton Petroleum Corporation is an independent, public company actively engaged in the exploration for and development and production of natural gas, natural gas liquids, and crude oil in western Canada. Our activities are concentrated in three core geographic areas, primarily in the province of Alberta, in the Western Canada Sedimentary Basin. Our growth and reserve base results predominantly from our exploration and development drilling programs.

Our objective has been and remains that of building an exploration and development company capable of delivering sustainable long term growth. Management has adhered to a consistent strategy in pursuing this objective, including:

- concentrating activities in a limited number of core areas;
- focusing on unconventional long life natural gas reserves in large resource plays;
- pursuing growth through the drill bit, complemented by strategic acquisitions;
- controlling infrastructure and operatorship; and
- maintaining financial flexibility.

Results of Operations

- Drilled 342 gross (274 net) wells with a 94% success rate.
- Achieved annual average production of 33,187 boe/d, a 13% increase from 2005.
- Generated cash flow from operations of $256.3 million or $1.92 per diluted share.
- Operating earnings for the year were $65.2 million.
- Net earnings for the year were $127.4 million.

Years ended December 31,	**2006**	2005	2004
Cash flow from operations [1] *($000s)*	**$ 256,305**	$ 278,112	$ 177,131
Per share: basic	**$ 2.01**	$ 2.21	$ 1.51
diluted	**$ 1.92**	$ 2.11	$ 1.43
Net earnings *($000s)*	**$ 127,426**	$ 81,326	$ 63,633
Per share: basic	**$ 1.00**	$ 0.65	$ 0.54
diluted	**$ 0.95**	$ 0.62	$ 0.51

(1) Cash flow from operations represents net earnings before depletion and depreciation, future income taxes, and other non-cash expenses.

Cash flow from operations in 2006 was $256.3 million as compared to $278.1 million in 2005, with lower commodity prices more than offsetting production gains. The negative effect of lower commodity prices on cash flow was reduced by realized gains of $36 million resulting from risk management activities during the year.

While 2006 cash flow from operations declined from the prior year's level, net earnings of $127.4 million in 2006 actually increased from 2005 due to the positive effect of future income tax recoveries resulting from reductions in statutory corporate income tax rates and the unrealized gains from risk management activities. The impact of these items is summarized in the schedule of Operating Earnings presented below.

OPERATING EARNINGS

Operating earnings is a non-GAAP measure that adjusts net earnings for non-operating items that Management believes reduce the comparability of our underlying financial performance between periods. The following Summary of Operating Earnings reconciles Net Earnings, determined in accordance with GAAP, to Operating Earnings and has been prepared to provide readers with information that is more comparable between periods.

SUMMARY OF OPERATING EARNINGS

Years ended December 31, ($000s, except per share amounts)	**2006**	2005	2004
Net earnings, as reported	**127,426**	$ 81,326	$ 63,633
Non-operational items, after tax			
Unrealized foreign exchange (gain)	**(550)**	(6,339)	(11,821)
Unrealized risk management (gain) loss	**(18,027)**	6,345	1,338
Stock-based compensation	**5,974**	3,682	2,094
Tender costs on repurchase of 9.90% notes	**–**	14,414	–
Future income tax recovery due to income tax rate reductions	**(49,655)**	(5,764)	(8,359)
Operating earnings	**$ 65,168**	$ 93,664	$ 46,885
Per share: basic	**$ 0.51**	$ 0.75	$ 0.40
diluted	**$ 0.49**	$ 0.71	$ 0.38

REVENUE

Revenue in 2006 decreased 4% as result of a 15% decrease in realized prices, despite a 13% increase in production volumes.

Years ended December 31,	**2006**	2005	2004
Average production			
Natural gas *(mmcf/d)*	**142**	131	123
Liquids *(bbls/d)*	**9,516**	7,646	6,330
Total *(boe/d)*	**33,187**	29,424	26,876
Benchmark prices			
NYMEX *(U.S.$/mmbtu)*	**$ 7.26**	$ 8.55	$ 6.09
AECO *($/GJ)*			
Monthly index	**$ 6.21**	$ 8.04	$ 6.44
Daily index	**$ 6.19**	$ 8.27	$ 6.18
WTI *(U.S.$/bbl)*	**$ 66.22**	$ 56.56	$ 41.40
Edmonton par *($/bbl)*	**$ 72.77**	$ 68.72	$ 52.37
Realized prices			
Natural gas *($/mcf)*	**$ 6.37**	$ 8.42	$ 6.46
Liquids *($/bbl)*	**58.53**	56.04	43.21
Total *($/boe)*	**$ 44.05**	$ 51.95	$ 39.82
Revenue *($000s)*			
Natural gas	**$ 330,349**	$ 401,468	$ 291,565
Liquids	**203,307**	156,411	100,094
Total	**$ 533,656**	$ 557,879	$ 391,659

SUMMARY OF REVENUE INCREASES FROM PRODUCTION AND PRICING

($000s)	Natural Gas Revenue	Liquids Revenue	Total Revenue
Reported 2005 revenue	$ 401,468	$ 156,411	$ 557,879
Increase in production volumes	26,427	39,951	66,378
Change in prices	(97,546)	6,945	(90,601)
Reported 2006 revenue	**$ 330,349**	**$ 203,307**	**$ 533,656**

Overall production in 2006 rose 13% from the prior year. Natural gas volumes increased 8%, while liquids production increased 24% over 2005 volumes. The growth in liquids production is largely the result of our ongoing conventional crude oil exploration and development program at Cecil and Worsley. Unfortunately, the year over year decline in North American natural gas prices overwhelmed the growth in production volumes.

We market the majority of our natural gas production through a combination of daily and monthly indexed contracts and aggregator contracts. During 2006, approximately 11% of our natural gas production remained committed to longer term aggregator contracts which realized a price that was, on average, $1.31/mcf less than that received on non-aggregator volumes.

Our crude oil sales are priced based upon Edmonton postings and are typically sold on 30 day evergreen arrangements. Natural gas liquids are bid out on an annual basis to obtain the most favourable pricing. We sell our crude oil and natural gas liquids primarily to refineries and marketers of crude oil and natural gas liquids.

Periodically we enter into financial instrument contracts to hedge against price volatility in funding our capital expenditure programs. This activity is fully disclosed in the Risk Management and Financial Instrument sections of this MD&A. At present approximately 30% of our production is hedged through to October 31, 2007. Depending on market conditions, we may enter into additional hedges throughout the year with a goal of hedging approximately 50% of future production volumes before royalties.

Years ended December 31, ($000s, except where noted)	**2006**	2005	2004
Crown royalties	**$ 100,230**	$ 105,827	$ 75,477
Other royalties	**23,447**	26,890	17,939
Net royalties	**$ 123,677**	$ 132,717	$ 93,416
Percentage of revenues	**23.2%**	23.8%	23.9%

Royalties are paid to various government entities and other land and mineral rights owners. Virtually all crown royalties are paid to the province of Alberta which has a royalty structure based upon commodity prices and well productivity, with higher prices and well productivity attracting higher royalty rates. Our royalty rate in 2006, as a percentage of revenue, decreased slightly from 2005 as a result of lower commodity prices in 2006.

We anticipate 2007 royalty rates will remain relatively consistent with prior years; however, this could change as the Alberta government has stated its intent to review the current royalty regime.

OPERATING EXPENSES

Years ended December 31,	**2006**	2005	2004
Operating expenses *($000s)*	**$ 95,462**	$ 66,802	$ 55,655
Operating expenses per boe *($/boe)*	**$ 7.88**	$ 6.22	$ 5.66

Cost pressures associated with an industry operating at maximum capacity resulted in increased operating costs during 2006 particularly when measured on a boe basis. Specific increases of note include salaries for field staff and contract operators and rising electricity prices. Additionally, liquids production increased 24% during the year as compared to the 8% increase in natural gas volumes. As the 2006 per unit operating expenses for liquids were approximately $3.60 per boe greater than natural gas per unit costs, the overall cost per boe rose to reflect the change in the oil/natural gas production mix.

With the current reduced level of activity in the industry, we are now beginning to see indications that cost inflation is moderating. With an increased emphasis on cost controls, we anticipate 2007 operating costs, on a unit of production basis, will remain similar to those experienced in 2006.

TRANSPORTATION EXPENSES

Years ended December 31,	**2006**	2005	2004
Transportation costs *($000s)*	**$ 12,564**	$ 10,858	$ 8,595
Transportation costs per boe *($/boe)*	**$ 1.04**	$ 1.01	$ 0.87

We incur charges for the transportation of our production from the wellhead to the point of sale. Pipeline tariffs and trucking rates for liquids are primarily dependent upon production location and distance from the sales point. Regulated pipelines transport natural gas within Alberta at tolls approved by the government.

While higher transportation costs in 2006 resulted from a combination of increased trucking costs associated with additional crude oil production and surcharges associated with high fuel costs, the cost per boe remained relatively constant to the prior year.

GENERAL AND ADMINISTRATIVE EXP

Years ended December 31, ($000s, except where noted)	**2006**	2005	2004
General and administrative expenses	**$ 38,321**	$ 34,638	$ 20,182
Capitalized general and administrative expenses	**(9,625)**	(11,158)	(2,982)
Operator recoveries	**(2,465)**	(2,257)	(1,985)
Total general and administrative expenses	**$ 26,231**	$ 21,223	$ 15,215
General and administrative per boe *($/boe)*	**$ 2.17**	$ 1.98	$ 1.55

Employee costs associated with increased personnel levels, together with a general increase in remuneration necessary to attract and retain qualified personnel in a very competitive industry, were the main contributors to the increase in general and administrative expenses in 2006. Other increases included insurance and costs associated with ongoing regulatory compliance requirements. During 2006, we incurred expenses totaling $1.1 million relating to compliance requirements pursuant to the U.S. Sarbanes-Oxley Act of 2002 and Canadian Multilateral Instrument 52-109.

Years ended December 31, ($000s, except where noted)	**2006**	2005	2004
Interest on bank debt, net	**$ 15,356**	$ 11,520	$ 9,662
Interest on Senior Notes	**35,880**	20,912	21,281
Interest expense	**51,236**	32,432	30,943
Finance charges	**2,839**	2,519	2,790
Total interest and finance charges	**$ 54,075**	$ 34,951	$ 33,733
Total interest and finance charges per boe ($/boe)	**$ 4.47**	$ 3.25	$ 3.44

Weighted average annual debt *($000's, except where noted)*	**2006**	2005
Bank debt	**$ 254,476**	$ 228,381
Effective interest rate	**5.60%**	4.23%
Senior notes *(US$)*	**$ 412,802**	$ 179,583
Effective interest rate	**7.64%**	9.50%

Interest expenses relating to bank debt in 2006 increased from the prior year as a result of increased borrowings incurred to fund our 2006 capital program and overall floating interest rate increases. The decrease in the effective interest rate incurred on the Senior Notes resulted from the repurchase of the 9.90% Senior Notes issued in 2002 with a portion of the proceeds of the 7.625% Senior Notes issued in 2005. Our debt instruments are more fully described in Notes 5 and 6 to our consolidated financial statements.

Years ended December 31, ($000s)	2005
Premium payment	$ 7,814
Consent solicitation fee	5,883
Reduction of deferred financing charges on repayment of 9.90% Senior Notes	7,053
Total tender costs	$ 20,750

In November 2005, we completed a tender offer and consent solicitation to purchase our 9.90% Senior Notes due in 2009. 96% of the Senior Notes were tendered to the offer and purchased by the Company. The unamortized portion of deferred financing charges relating to the tendered portion of the 9.90% Senior Notes is included in tender costs. The remaining 4% of the Notes were purchased in 2006 pursuant to the call option provisions and no additional tender costs were incurred.

Years ended December 31, ($/boe)	**2006**	2005	2004
Realized price	**$ 44.05**	$ 51.95	$ 39.82
Commodity hedge gain (loss)	**3.24**	(0.90)	(0.93)
Royalties	**(10.21)**	(12.36)	(9.50)
Operating expenses	**(7.88)**	(6.22)	(5.66)
Transportation	**(1.04)**	(1.01)	(0.87)
Field operating netback	**$ 28.16**	$ 31.46	$ 22.86
General and administrative	**(2.17)**	(1.98)	(1.55)
Interest	**(4.47)**	(3.25)	(3.43)
Current taxes	**–**	(0.47)	(0.28)
Cash flow netback	**$ 21.52**	$ 25.76	$ 17.60

RISK MANAGEMENT

Our financial results are impacted by external market risks associated with fluctuations in commodity prices, interest rates, and the Canadian/U.S. exchange rate. We utilize various financial instruments for non-trading purposes to manage and mitigate our exposure to these risks. Our financial instruments are not designated for hedge accounting, and accordingly are recorded at fair value on the consolidated balance sheets, with subsequent changes recognized in consolidated net earnings.

Financial instruments utilized to manage risk are subject to periodic settlements throughout the term of the instruments. Such settlements may result in a gain or loss, which is recognized as a realized risk management gain or loss at the time of settlement.

The mark-to-market fair values of the financial instruments outstanding at the end of a reporting period reflect the values of the instruments based upon market conditions existing as of that date. Any change in the fair values of the instruments from that determined at the end of the previous reporting period is recognized as an unrealized risk management gain or loss. Unrealized risk management gains or losses may or may not be realized in subsequent periods depending upon subsequent moves in commodity prices, interest rates, or exchange rates affecting the financial instruments.

The mark-to-market fair value method of accounting for financial instruments and the recognition of unrealized gains and losses in determining earnings has introduced an additional element of volatility into our earnings that may not be particularly meaningful in assessing our financial performance.

Risk management gains and losses recognized in 2006 are outlined below.

Years ended December 31, ($000s)	**2006**	2005	2004
Commodity contracts			
Realized (gain) loss	**$ (39,217)**	$ 9,663	$ 9,151
Unrealized (gain) loss	**(25,775)**	5,136	(1,985)
Foreign currency contracts			
Realized (gain)	**(1,405)**	–	–
Cross currency interest rate swap			
Realized loss (gain)	**4,423**	(532)	(2,522)
Unrealized (gain) loss	**(1,747)**	5,035	4,164
Total risk management (gain) loss	**$ (63,721)**	$ 19,302	$ 8,808
Realized (gain) loss	**$ (36,199)**	$ 9,131	$ 6,629
Unrealized (gain) loss	**(27,522)**	10,171	2,179
Total risk management (gain) loss	**$ (63,721)**	$ 19,302	$ 8,808

DEPLETION AND DEPRECIATION

Years ended December 31,	**2006**	2005	2004
Total depletion and depreciation *($000s)*	**$ 143,057**	$ 105,504	$ 82,554
Depletion and depreciation per boe *($/boe)*	**$ 11.81**	$ 9.82	$ 8.39

Accelerated capital programs and competition throughout the oil and gas industry during the year increased the demand and costs of goods and services. This increase in costs is reflected in higher finding, development, and on-stream costs which in turn, have resulted in an increase in depletion and depreciation rates on a boe basis in the current year in comparison to prior periods.

The foreign exchange gain recognized on the consolidated statements of earnings results primarily from the translation of our U.S. dollar denominated Senior Notes into Canadian dollars. The Senior Notes are translated and recorded in the financial statements at the year end exchange rate, with any differences from prior measurements being recognized as an unrealized foreign exchange gain or loss.

The Canadian/U.S. exchange rate increased marginally to one Canadian Dollar being equal to U.S.$0.8581 as at December 31, 2006, from one Canadian Dollar being equal to U.S.$0.8577 as at December 31, 2005, resulting in the recognition of a $1 million foreign exchange gain in 2006.

On November 22, 2005, pursuant to a tender offer, we repurchased U.S.$158 million of the 9.90% Senior Notes issued in 2002. As a result of the repurchase, we crystallized $62 million of the accumulated unrealized foreign exchange gains in 2005 that had previously been recognized with the strengthening of the Canadian dollar subsequent to the note issuance.

Years ended December 31,	**2006**	2005	2004
Options granted *(000s)*	**2,228**	2,930	2,549
Weighted average fair value of options granted *($/share)*	**$ 6.90**	$ 5.45	$ 3.70
Stock-based compensation expense recognized *($000s)*	**$ 10,488**	$ 5,903	$ 3,410

We have a stock option plan for employees, Officers, and Directors. The plan is designed to attract, motivate, and retain outstanding individuals and to align their success with that of our Shareholders. The fair value of options granted is estimated on the date of grant using the Black-Scholes option pricing model and the associated compensation expense is recognized over the vesting period.

During 2006, in recognition of the shortage of and competition for qualified personnel that currently exists within the industry, we implemented an Employee Retention Program in July 2006 for our existing employees, excluding Officers and Directors. Under the program, and contingent upon various conditions existing on July 1, 2007, including the market value of the Company's shares, we may incur additional compensation expense to a maximum amount of $4.2 million. For the year ended December 31, 2006, we have accrued $1.4 million in stock-based compensation in relation to this program.

Income taxes are recorded using the liability method of accounting. Future income taxes are calculated based on the difference between the accounting and income tax basis of an asset or liability. The classification of future income taxes between current and non-current is based upon the classification of the liabilities and assets to which the future income tax amounts relate. The classification of a future income tax amount as current does not imply a cash settlement of the amount within the following twelve month period.

CURRENT INCOME TAXES

Current taxes decreased to nil in 2006 from $5 million in 2005 (2004 - $3 million) due partially to the elimination of federal capital tax effective January 1, 2006. Current taxes in 2005 also included $3 million related to the resolution of a Notice of Objection with respect to a corporate acquisition in a prior tax period. As a result of the reassessment resulting from resolution of the Notice of Objection, $7 million of tax deductible exploration expenses denied to the acquired corporation were added to our income tax pools as a positive offset to incurring the current liability. The resolution of this matter did not impact our total future income tax expense for 2006.

FUTURE INCOME TAXES

Future taxes in 2006 included a $50 million recovery as a result of reductions in the federal and Alberta corporate tax rates, which were enacted in the second quarter of 2006. The federal tax rate is to be reduced from 22.1% to 19% over a 3 year period starting January 1, 2008 and the Alberta tax rate was reduced from 11.5% to 10.0% effective April 1, 2006.

CORPORATE TAX RATES

Years ended December 31,	**2006**	2005	2004
Statutory rate	34.5%	37.6%	38.6%
Effective rate	(2.8)%	39.5%	35.0%

A reconciliation of our effective tax rate to the statutory rate may be found in Note 15a to the consolidated financial statements.

TAX POOLS

The following table summarizes our estimated tax pool balances by classification.

As at January 1, 2007	Available Balance ($000s)	Maximum Annual Deduction
Canadian exploration expense	$ 169,735	100%
Canadian development expense	421,500	30%
Canadian oil and natural gas property expense	260,146	10%
Undepreciated capital cost and financing costs	318,105	~ 25%
Total	$ 1,169,486	

A significant portion of our taxable income is generated by a wholly owned partnership. Consolidated earnings before income taxes include $259 million (2005 - $263 million) of partnership earnings that will be included in the following year's income for income tax purposes. Future income taxes include $83 million (2005 - $94 million) as a result of this deferral of partnership earnings.

Based upon planned capital expenditure programs and current commodity price assumptions, it appears we will not incur current income taxes until at least 2010.

SUMMARY OF CAPITAL EXPENDITURES

	2006		2005		2004	
Years ended December 31,	**($000s)**	**%**	($000s)	%	($000s)	%
Drilling and completions	**$ 294,197**	**60**	$ 318,502	66	$ 175,003	62
Land and seismic	**59,905**	**12**	55,469	11	38,326	14
Facilities	**137,409**	**28**	109,729	23	68,861	24
Sub-total	**491,511**	**100**	483,700	100	282,190	100
Acquisitions and divestments, net	**34,394**		28,575		22,825	
Sub-total	**525,905**		512,275		305,015	
MPP	**(31)**		1,261		11,386	
Total capital expenditures	**$ 525,874**		$ 513,536		$ 316,401	

Capital spending in 2006 was directed towards the continued development of our core natural gas resource plays in southern and central Alberta and our conventional oil play in the Peace River Arch.

Capital expenditures, before acquisitions and divestitures, in 2006 increased only marginally from 2005; however, they reflect overall cost inflation experienced in the industry during the year. We drilled a total of 274 net wells in 2006 at an average cost, to drill and complete, of $1,074,000 per well. In contrast, we drilled 334 net wells during 2005 at an average cost of $954,000 per well. Although not an entirely comparable analysis, as the mix of shallow, deep, and oil wells will also affect this comparison, this represents a 12.6% increase in drilling and completion costs, on a per well basis, in 2006 as compared to 2005.

Spending on production facilities increased $27.7 million over 2005 and comprised 28% of our total capital program, before acquisitions and divestments as compared to 23% in 2005. Although we deferred a portion of our initial 2006 drilling program in deference to lower commodity prices and the inflationary cost environment, we continued with the majority of our planned expenditures relating to equipment and facilities. This spending should allow us to place new production on-stream more quickly in 2007.

Consistent with the focus on our natural gas resource plays, we expanded our land position and working interests in core areas through a number of acquisitions at a total cost of $34.4 million.

To assist in funding our capital programs, we entered into agreements for the divestment of two minor non-operated properties prior to year end. Net proceeds of $45.9 million relating to these divestments were received subsequent to December 31, 2006 and have not been recognized in 2006, net of acquisitions and divestments. These funds have been deployed in the ongoing development of our resource plays and we plan to continue this strategy of capital redeployment in the future.

With the current slow-down in industry activity, we are beginning to see evidence of a reduction in the cost of certain goods and services. Costs are expected to moderate over the year in select areas, which combined with our increased emphasis on capital discipline and cost control, should have an overall positive affect on 2007 capital efficiencies.

Liquidity and Capital Resources

As at December 31, ($000s, except where noted)	2006 Pro forma [3]	2006	2005	2004
Working capital deficiency [1]	$ (24,706)	$ **21,163**	$ 62,116	$ 603
Bank debt	330,000	**330,000**	177,900	220,000
Senior term notes	524,385	**524,385**	357,640	198,594
Total indebtedness	$ 829,679	$ **875,548**	$ 597,656	$ 419,197
Capital stock	$ 231,992	$ **231,992**	$ 226,444	$ 135,526
Contributed surplus	16,974	**16,974**	9,173	3,840
Retained earnings	485,158	**485,158**	360,719	284,712
Shareholders' equity	$ 734,124	$ **734,124**	$ 596,336	$ 424,078
Debt to cash flow from operations [2]	3.2	**3.4**	2.2	2.4
Debt to book capitalization	53%	**54%**	50%	50%
Debt to market capitalization	38%	**39%**	22%	25%

(1) *Excludes unrealized risk management items net of related future income taxes.*

(2) *Based on trailing 12 month cash flow from operations.*

(3) *In December 2006, Compton entered into agreements for the sale of two minor, non-core properties that generated net proceeds of $45.9 million, all of which were received in the first quarter of 2007. The effective dates of these sales were as of year end. Accordingly, we excluded these properties from the December 31, 2006 reserve report, the details of which are set out in the Annual Information Form and elsewhere in the Annual Report. Canadian Generally Accepted Accounting Principles require that we recognize the transactions as at dates of closing in 2007. The pro forma numbers presented above reflect the effect of the receipt of the net proceeds of $45.9 million as at December 31, 2006, consistent with the presentation of reserves data as set out in the Annual Information Form.*

Our corporate debt is structured to provide us with financial flexibility. Of our existing debt, 61% consists of Senior Notes that are not due until 2013, giving us the ability to draw on our senior secured credit facilities to assist in funding our planned 2007 capital program.

During the fourth quarter of 2006, we entered into agreements for the sale of two minor, non-core properties. The sale of these properties were recorded in 2007 concurrent with the closing of the sales. We are also pursuing the monetization of $25 million of production facilities that are expected to close in early April 2007. The sale of additional non-core properties and certain major conventional oil properties remains a potential source of funds for the continued development of our overall natural gas resource play strategy.

In November 2006, we expanded our banking syndicate adding four additional banks including several U.S. based banking institutions. Concurrent with the increase in syndicate members, we increased our authorized senior secured facilities to $500 million consistent with the Company's borrowing base. The terms and conditions of the increased facilities remain the same as those established upon renewal of the facilities in July 2006. Our borrowing base is determined based upon year end reserves. With the increase in 2006 reserves over 2005, we anticipate the borrowing base will increase. We do not, however, expect to request an increase in our authorized credit facilities at this time.

We believe internally generated cash flow from operations, proceeds from property dispositions, and funds available through our expanded credit facilities will be more than sufficient to fund our planned 2007 capital program, while still maintaining an appropriate capital structure.

As part of normal business, we have entered into arrangements and incurred obligations that will impact our future operations and liquidity, some of which are reflected as liabilities in the consolidated financial statements. The following table summarizes our contractual obligations as at December 31, 2006.

	Payments Due by Period			
($000s)	Less than 1 year	1-3 years	4-5 years	After 5 years
Operating leases	$ 3,737	$ 6,211	–	–
Office facilities	$ 3,509	$ 14,523	$ 9,600	$ 24,000
MPP partnership distributions	$ 9,172	$ 12,229	–	–
Total	$ 16,418	$ 32,963	$ 9,600	$ 24,000

We have the ability and the intention to extend the term of our bank borrowings and therefore repayment of the facility is not included in the schedule of contractual obligations above.

Outlook and Guidance for 2007

Consistent with general industry thinking, we are of the opinion that natural gas prices will strengthen during 2007. We are also of the opinion that the cost of specific goods and services will moderate during the year.

In the interim, we believe it prudent to move forward with a relatively moderate capital spending program. During 2007, the majority of our activities will focus on the continued development and delineation of our natural gas resource plays. We will concentrate on development drilling and the acceleration of on-stream timing with a view to production growth. At the same time, increased emphasis will be placed on capital discipline and efficiency. Equally important is our need to increase our complement of qualified personnel for the expansion of operations necessary to realize on our opportunities in an efficient manner. We view the current reduction in industry activity as an opportunity to attract additional staff in preparation for increased drilling programs in the last half of 2007 and into 2008.

The following section summarizes our plans and guidance for 2007.

	2007 Budget Range
Capital expenditures *($millions)*	$375
Gross wells	330
Average production - total boe/d	37,000 to 38,000
Cash flow from operations ($millions)	$310 to $320

Our 2007 projected cash flow from operations is based upon the following pricing assumptions:

	Benchmark	Realized
Natural gas	AECO Cdn $7.30/GJ	Cdn $7.50/mcf
Crude oil *($/bbl)*	WTI U.S. $62.00/bbl	Cdn $60.00/bbl

The average Canadian/U.S. exchange rate is budgeted at $0.89 U.S. = $1.00 Cdn.

CASH FLOW SENSITIVITIES

($millions)	Change in Cash Flow
Change of Cdn $0.25/mcf in the benchmark AECO natural gas price	$12
Change of U.S. $1.00/bbl in the benchmark WTI oil price	$ 2

In the event of significant decreases in commodity prices, increases in exploration costs, or an overall economic downturn, our capital expenditure program can be readily modified.

Additional Disclosures

CONTROLS AND PROCEDURES

With respect to disclosure controls and procedures and internal control over financial reporting, we are required to comply with the U.S. Sarbanes-Oxley Act of 2002 and Canadian Multilateral Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. These regulations are substantially the same. However, the most significant difference is the U.S. requirement for the registered public accounting firm that audits our financial statements, included in our annual report, to issue an attestation report on our assessment of internal control over financial reporting. There is no corresponding Canadian attestation requirement.

There are certain procedural and wording differences between the U.S. and Canadian certifications. We have chosen to file the form of certification pursuant to Section 302 of the Sarbanes-Oxley Act with the U.S. Securities and Exchange Commission ("SEC") and Form 52-109 F1, Certification of Annual Filings, with the Ontario Securities Commission ("OSC").

We have complied with both the U.S. and Canadian requirements in respect of disclosure controls and procedures and internal control over financial reporting and our report is below.

MANAGEMENT'S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The term "disclosure controls and procedures" is defined, under Rule 13a-15(d) of the Exchange Act, as controls and other procedures that are designed to ensure both non-financial and financial information required to be disclosed by us in our periodic reports is recorded, processed, summarized, and reported within the time periods required. This information is accumulated and communicated to management as appropriate to allow for timely decisions regarding required disclosures. The definition of disclosure controls and procedures with respect to Canadian Multilateral Instrument 52-109 is substantially the same.

As indicated in our certifications filed with the SEC and OSC, we completed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2006, under the supervision and with the participation of our Management, including our President & CEO and VP Finance & CFO. Based upon our evaluation, we concluded our disclosure controls and procedures were effective in all material respects.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including our President & CEO and VP Finance & CFO, is responsible for establishing and maintaining adequate internal control over financial reporting. The term "internal control over financial reporting" is defined, under both Rule 13a-15(f) of the Exchange Act and Canadian Multilateral Instrument 52-109, as processes designed by, or under the supervision of, our principal executive and principal financial officers, and effected by our board of directors,

management and other personnel to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with GAAP. These controls include policies and procedures that:

1. Pertain to the maintenance of our records, that accurately and fairly reflect the transactions and dispositions of our assets;

2. Provide reasonable assurance that transactions are recorded to be able to prepare our financial statements in accordance with GAAP, and that our receipts and expenditures are made only in accordance with authorizations of our management and directors; and

3. Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets, which could have a material effect on our financial statements.

We completed an evaluation of the effectiveness of the design and operation of our internal control over financial reporting under the supervision, and with the participation, of our Management, including our President & CEO and VP Finance & CFO. We conducted our evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control - Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission, also known as COSO. Based upon our evaluation, we have concluded that, as of December 31, 2006, the internal control over financial reporting were effective in all material respects.

Our assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 was audited by Grant Thornton LLP, Chartered Accountants, the independent registered public accounting firm which also audits our financial statements.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes during the last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Accounting estimates require us to make assumptions regarding matters that are uncertain at the time the estimate is made and may have a material impact on our financial condition. A comprehensive discussion of our significant accounting policies may be found in Note 1 to the consolidated financial statements.

PETROLEUM AND NATURAL GAS RESERVES

The independent petroleum engineering and geological consulting firm of Netherland, Sewell & Associates, Inc. evaluated and reported on 94% of our petroleum and natural gas reserves and audited the Company's internal evaluation of the remainer.

The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. We expect that our estimates of reserves may change with updated information from the results of future drilling, testing, or production levels. Such changes could be upwards or downwards. Reserve estimates have a material impact on depletion and depreciation, asset retirement obligations, and impairment costs, all of which could possibly have a material impact on our consolidated net earnings.

DEPLETION

Capitalized costs and estimated future expenditures to develop proved reserves, including abandonment costs, are depleted based on the proportion of estimated proved oil and natural gas reserves produced during the year compared to total proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If it is determined that properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized.

In 2006, we incurred $143 million of depletion and depreciation. If our proved reserves were to increase by 5%, our depletion and depreciation expense would decrease by $1.6 million and consolidated net earnings after tax would increase by $1.1 million. If our proved reserves were to decrease by 5%, our depletion and depreciation expense would increase by $1.9 million and consolidated net earnings after tax would decrease by $1.2 million.

IMPAIRMENT

In applying the full cost method of accounting, we periodically calculate a ceiling or limitation on the amount that property and equipment may be carried for on the consolidated balance sheets. An impairment exists if the undiscounted future net cash flows from proved reserves at future commodity prices plus the cost of undeveloped properties is less than the carrying value of the capitalized costs. As at December 31, 2006, the ceiling amount calculated was $2.7 billion (2005 - $2.5 billion) in excess of the carrying value of the costs capitalized.

If an impairment is found to exist, the impaired properties are written down to their fair value. The fair value of the assets is calculated based on future net cash flows from proved plus probable reserves, discounted at a risk free interest rate using future commodity prices, plus the cost of undeveloped properties. An impairment may result in a material loss for a particular period; however, future depletion and depreciation expense would be reduced as a result.

Assumptions about reserves and future prices are required to calculate future net cash flows. The assumptions made to estimate reserves have been discussed above. There is significant uncertainty regarding forecasting future commodity prices due to economic and political uncertainties. Future prices are derived from a consensus of price forecasts among recognized reserve evaluators. Estimates of future cash flows assume a long term price forecast and current operating costs per boe plus an inflation factor.

It is difficult to determine and assess the impact of a decrease in proved reserves on impairment. The relationship between reserve estimates and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test is complex. As a result, it is not possible to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on impairment. No material downward revisions to our reserves are anticipated.

ASSET RETIREMENT OBLIGATION

We recognize the fair value of estimated asset retirement obligations on the consolidated balance sheet when a reasonable estimate of fair value can be made. Asset retirement obligations include those legal obligations where we will be required to retire tangible long term assets such as well sites, pipelines, and facilities. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long term assets. Increases in the asset retirement obligations resulting from the passage of time are recorded as accretion of asset retirement obligations in the consolidated statement of earnings. Amounts recorded for asset retirement obligations are subject to uncertainty associated with the method, timing, and extent of future retirement activities. Actual payments to settle the obligations may differ from estimated amounts.

In 2005, the Canadian Institute of Chartered Accountants (CICA) issued three new accounting standards: Handbook Section 1530, *"Comprehensive Income"*, Handbook Section 3855, *"Financial Instruments - Recognition and Measurement"*, and Handbook Section 3865, *"Hedges"*. The new standards introduce the Consolidated Statement of Comprehensive Income which is used to temporarily provide for gains and losses including foreign currency translation adjustments and other amounts arising from changes in fair value until they are realized and recorded in net income. As well, all financial instruments, including derivatives, are to be included in our consolidated balance sheet and measured at fair value. In certain situations assets that are classified as held to maturity will continue to be measured at cost. The new standards also include further clarification on the application of hedge accounting which will have no impact on our financial statements which currently use mark-to-market accounting for derivative instruments. These new standards are effective for fiscal years beginning on or after October 1, 2006 and early adoption is permitted. We have assessed the impact of these new accounting standards on the consolidated financial statements at January 1, 2007 and have determined that:

The balance in deferred financing charges will no longer be disclosed separately but will be netted against the corresponding Senior Notes.

The presentation of accumulated other comprehensive income will be similar to the presentation of United States accounting principles and reporting included in Note 20 to the Consolidated Financial Statements.

The measurement and recording of financial instruments at fair value will not have a material impact on our consolidated financial statements.

In July 2006, the CICA replaced Handbook Section 1506, *"Accounting Changes"* with a new Section 1506, *"Accounting Changes"* to harmonize with International Accounting Standards for the accounting and disclosure of changes in accounting estimates and errors. Under the new standard, accounting changes should be applied retrospectively unless otherwise permitted or where impracticable to determine. In addition, voluntary changes in accounting policy are made only if they result in the financial statements providing reliable and more relevant information. New disclosure is required for changes in accounting policies, changes in accounting estimates and correction of errors. The standard is effective for fiscal years beginning on or after January 1, 2007 and we do not expect the application of this revised standard to have a material impact on our consolidated financial statements.

In December 2006, the CICA issued two new accounting standards: Handbook Section 3862, *"Financial Instruments - Disclosures"* and Section 3863, *"Financial Instruments - Presentation"*. The new standards will require increased disclosure of financial instruments with particular emphasis on the risks associated with recognized and unrecognized financial instruments and how those risks are managed. The standards are effective for fiscal years beginning on or after October 1, 2007 and we are currently assessing the impact on the consolidated financial statements.

In December 2006, the CICA issued a new accounting standard: Handbook Section 1535, *"Capital Disclosures"*, requiring disclosure of information about an entity's capital and the objectives, policies, and processes for managing capital. The standard is effective for fiscal years beginning on or after October 1, 2007 and we are currently assessing the impact on the consolidated financial statements.

RISK MANAGEMENT

Our operations are subject to risks inherent to the oil and natural gas industry. We are exposed to financial risks including fluctuations in commodity prices, currency exchange rates, interest rates, credit ratings, and changing expenditure costs due to shifts in market conditions. We take specific measures to manage these risks, particularly those impacting cash flow from operations.

A more detailed discussion of risk factors is presented in our most recent Annual Information Form, filed with securities regulatory authorities on or before March 30, 2007 on www.sedar.com.

COMMODITY PRICE RISK MANAGEMENT

We enter into commodity price contracts to actively manage risk associated with price volatility to protect cash flow from operations required to fund our capital program. We use costless collars as well as balancing physical and financial contracts in terms of volumes, timing of performance, and delivery obligations to manage risk. Net open positions may exist or may be established to take advantage of market conditions. Net earnings for the year ended December 31, 2006, include realized and unrealized gains of $65 million (2005 - $15 million loss) on these transactions.

The following table outlines commodity hedge transactions in place at December 31, 2006 together with transactions entered into subsequent to the year end:

Commodity	Term	Amount	Average Price	Index
Natural gas				
Collar	Nov. 2006 - Mar. 2007	40,000 GJ/d	Cdn$8.03 - $10.62	AECO
Collar	Apr. 2007 - Oct. 2007	45,000 GJ/d	Cdn$6.61 - $8.77	AECO
Crude oil				
Collar	Jan. 2007 - Dec. 2007	3,000 bbls/d	U.S.$75.00 - $84.55	WTI

FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

We are exposed to fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Commodity prices are based on U.S. dollar benchmarks that result in our realized price being influenced by the Canadian/U.S. currency exchange rate. Should the Canadian dollar strengthen compared to the U.S. dollar, the negative effect on net earnings would be partially offset by foreign exchange gains on our U.S. dollar denominated Senior Notes. Conversely, should the Canadian dollar weaken compared to the U.S. dollar, the positive effect on net earnings would be partially offset by foreign exchange losses on our U.S. dollar denominated Senior Notes. Cash flow from operations is not impacted by the effects of currency fluctuations on our U.S. dollar denominated Senior Notes.

INTEREST RATE RISK MANAGEMENT

Concurrent with the closing of our 9.90% Senior Notes offering in May of 2002, we entered into a cross currency interest rate swap. The swap, which converted fixed rate U.S. dollar interest obligations into floating rate Canadian dollar interest obligations, was entered into to fix the exchange rate on interest payments and take advantage of lower floating interest rates. On repurchase of the majority of 9.90% Senior Notes in November 2005, we elected not to collapse the swap and incur the associated costs of $12 million. The swap remains outstanding and at December 31, 2006, we valued the liability relating to future unrealized losses on the swap arrangement to be $11 million (2005 - $15 million) determined on a mark-

to-market basis. The loss associated with the swap has resulted primarily from the strengthening of the Canadian dollar. Should the Canadian dollar continue to increase against the U.S. dollar, the loss could increase further; alternatively if the Canadian dollar were to weaken the loss would be reduced. Cash settlements of the swap positions are made semi-annually and losses realized will be recorded over the remaining term of the swap agreement which expires in May 2009.

The following tables set out selected quarterly financial information for the last two fiscal years.

		Three Months Ended			Year Ended
($000s, except where noted)	March 31, 2006	June 30, 2006	Sept. 30, 2006	Dec. 31, 2006	Dec. 31, 2006
Average production *(boe/d)*	34,029	32,645	32,843	33,245	33,187
Average pricing *($/boe)*	$ 48.21	$ 44.85	$ 41.33	$ 41.82	$ 44.05
Total revenue	$ 147,644	$ 133,224	$ 124,886	$ 127,902	$ 533,656
Cash flow from operations	$ 73,596	$ 67,326	$ 60,120	$ 55,263	$ 256,305
Per share: basic	$ 0.58	$ 0.53	$ 0.47	$ 0.43	$ 2.01
diluted	$ 0.55	$ 0.50	$ 0.45	$ 0.42	$ 1.92
Operating earnings	$ 22,249	$ 17,947	$ 13,150	$ 11,822	$ 65,168
Net earnings (loss)	$ 38,002	$ 68,744	$ 30,717	$ (10,037)	$ 127,426
Per share: basic	$ 0.30	$ 0.54	$ 0.24	$ (0.08)	$ 1.00
diluted	$ 0.28	$ 0.51	$ 0.23	$ (0.08)	$ 0.95

During the second half of 2006, lower realized commodity prices from those experienced during the first half of the year resulted in reduced revenue, cash flow, and operating earnings. Production increases in the third and fourth quarter were more than offset by the reduction in commodity prices. The negative effect of lower commodity prices on cash flow was reduced by realized gains of $36 million from risk management activities. Net earnings for the nine months ended September 30, 2006 benefited from an unrealized foreign exchange gain of $19.1 million, after tax, and an income tax recovery of $35 million. Net earnings in the fourth quarter were negative due to the reversal of unrealized foreign exchange gains recorded in prior quarters, as the result of the weakening of the Canadian dollar compared to the U.S. dollar.

		Three Months Ended			Year Ended
($000s, except where noted)	March 31, 2005	June 30, 2005	Sept. 30, 2005	Dec. 31, 2005	Dec. 31, 2005
Average production *(boe/d)*	28,714	28,877	29,041	31,042	29,424
Average pricing *($/boe)*	$ 41.25	$ 46.33	$ 54.31	$ 64.58	$ 51.95
Total revenue	$ 106,589	$ 121,748	$ 145,114	$ 184,428	$ 557,879
Cash flow from operations	$ 52,277	$ 62,006	$ 74,189	$ 89,640	$ 278,112
Per share: basic	$ 0.43	$ 0.49	$ 0.58	$ 0.71	$ 2.21
diluted	$ 0.41	$ 0.47	$ 0.56	$ 0.67	$ 2.11
Operating earnings	$ 15,534	$ 18,923	$ 25,794	$ 33,413	$ 93,664
Net earnings	$ 10,059	$ 22,034	$ 11,127	$ 38,106	$ 81,326
Per share: basic	$ 0.08	$ 0.18	$ 0.09	$ 0.30	$ 0.65
diluted	$ 0.08	$ 0.17	$ 0.08	$ 0.29	$ 0.62

As compared to 2004, total revenue increased throughout 2005 as the result of high commodity prices and increasing production volumes. Average production increased in the third and fourth quarters, after abnormally wet weather in the summer restricted access in southern Alberta resulting in flat production volumes in the second quarter. Quarterly net earnings fluctuated due to non-operational items such as unrealized risk management gains and losses and unrealized foreign exchange losses.

SELECTED ANNUAL INFORMATIO

Years ended December 31, ($000s)	**2006**	2005	2004
Total revenue	**$ 533,656**	$ 557,879	$ 391,659
Net earnings	**$ 127,426**	$ 81,326	$ 63,633
Per share: basic	**$ 1.00**	$ 0.65	$ 0.54
diluted	**$ 0.95**	$ 0.62	$ 0.51
Total assets	**$ 2,147,472**	$ 1,758,098	$ 1,330,611
Total long term financial liabilities	**$ 854,385**	$ 535,540	$ 198,594

Total revenue in 2006 was marginally lower than 2005 with increases in production being more than offset by reduced commodity prices. Net earnings in 2006 increased $46.1 million over 2005 primarily as a result of risk management gains that offset the reduction in revenue and increases in expenses. Long term financial obligation in 2006 increased over 2005 as a result of increased borrowings to fund the capital programs.

Total revenue in 2005 was higher than in the previous year due to a combination of increased production and higher commodity prices. Net earnings in 2005 increased 28% from 2004, but was reduced by non-recurring costs of $14 million ($21 million before taxes) relating to the repurchase of U.S.$158 million of 9.90% Senior Notes. Total assets increased from the prior year primarily due to capital expenditures of $514 million. The change in long term financial liabilities at December 31, 2005 resulted from issuing U.S.$300 million Senior Notes and reclassifying bank debt as long term.

TRADING AND SHARE STATISTI

As at March 19, 2007 there were 128,569,676 common shares outstanding as well as 12,430,677 stock options.

	2006		2005(1)		2004
	TSX	**NYSE**	TSX	NYSE	TSX
Average daily trading volume *(000s)*	**545,489**	**115,450**	736,416	138,288	674,764
Share price *($/share)*					
High	**$ 19.24**	**US$ 16.74**	$ 18.66	US$ 16.11	$ 11.43
Low	**$ 10.20**	**US$ 9.04**	$ 9.80	US$ 14.15	$ 5.89
Close	**$ 10.65**	**US$ 9.12**	$ 17.10	US$ 14.65	$ 10.85
Market capitalization					
at December 31 *($000s)*	**$1,368,557**		$2,176,197		$1,273,290
Shares outstanding *(000s)*	**128,503**		127,263		117,354

(1) Trading on the New York Stock Exchange commenced on December 5, 2005.

6. Further Information

Additional information, including our Annual Information Form, is available on the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com.

Certain information contained herein constitutes forward looking statements under the meaning of applicable securities laws, including the United States Private Securities Litigation Reform Act of 1995. Forward looking statements include estimates, plans, expectations, opinions, forecasts, projections, guidance or other statements that are not statements of fact, including statements regarding (i) cash flow, production, capital expenditures and planned wells in 2007, and (ii) other risks and uncertainties described from time to time in the reports and filings made by us with securities regulatory authorities. Although we believe that the expectations reflected in such forward looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. There are many factors that could cause forward looking statements not to be correct, including risks and uncertainties inherent in our business. These risks include, but are not limited to: crude oil and natural gas price volatility, exchange rate fluctuations, availability of services and supplies, operating hazards and mechanical failures, uncertainties in the estimates of reserves and in projections of future rates of production and timing of development expenditures, general economic conditions, the actions or inactions of third party operators and regulatory pronouncements. We may, as considered necessary in the circumstances, update or revise forward looking information, whether as a result of new information, future events, or otherwise. Our forward looking statements are expressly qualified in their entirety by this cautionary statement.

Included in the MD&A and elsewhere in this report are references to terms used in the oil and gas industry such as cash flow from operations, cash flow per share and operating earnings. These terms are not defined by GAAP in Canada and consequently are referred to as non-GAAP measures. Non-GAAP measures do not have any standardized meaning and therefore reported amounts may not be comparable to similarly titled measures reported by other companies.

Cash flow from operations should not be considered an alternative to, or more meaningful than, cash provided by operating, investing and financing activities or net earnings as determined in accordance with Canadian GAAP, as an indicator of our performance or liquidity. Cash flow from operations is used by us to evaluate operating results and our ability to generate cash to fund capital expenditures and repay debt.

Operating earnings represents net earnings excluding certain items that are largely non-operational in nature and should not be considered an alternative to, or more meaningful than, net earnings as determined in accordance with Canadian GAAP. Operating earnings is used by us to facilitate comparability of earnings between periods.

The oil and natural gas industry commonly expresses production volumes and reserves on a barrel of oil equivalent ("boe") basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved measurement of results and comparisons with other industry participants. We use the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. However, boes do not represent a value equivalency at the plant gate where we sell our production volumes and therefore may be a misleading measure if used in isolation.

Consolidated Financial Statements

Management's Report

The accompanying Consolidated Financial Statements of Compton Petroleum Corporation (the "Company") are the responsibility of Management and have been prepared by Management in accordance with Canadian generally accepted accounting principles and policies stated in the notes to the Consolidated Financial Statements. Financial information contained throughout the annual report to shareholders is consistent with these financial statements.

The Company's Board of Directors has approved the Consolidated Financial Statements on the recommendation of the Audit Finance and Risk Committee, which has a written mandate that complies with the current requirements of Canadian securities legislation and the United States Sarbanes-Oxley Act of 2002.

Disclosure controls and procedure are designed to provide reasonable assurance that information required to be disclosed in reports filed with securities regulatory authorities is recorded, processed, summarized and presented in accordance with Canadian and United States securities laws. Management has evaluated the effectiveness of the Company's design and operation of disclosure controls and procedures as of December 31, 2006 and has concluded that the Company's disclosure controls and procedures were effective in all material respects.

OVER FINANCIAL REPORTING

Management is also responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Internal control, as more fully described in Management's Discussion and Analysis, includes policies and procedures designed to provide reasonable assurance relating to the reliability, completeness and timeliness of financial reporting. Management has assessed the effectiveness of the design and operation of internal control over financial reporting based on the Internal Control Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission, ("COSO"). Based on this assessment, Management has concluded that, as of December 31, 2006, internal control over financial reporting was effective in all material respects.

Grant Thornton LLP, an independent firm of chartered accountants, appointed by shareholders, has provided independent opinions on both the Consolidated Financial Statements and Management's assessment of the effectiveness of the Company's internal control over financial reporting as at December 31, 2006.

E.G. SAPIEHA, C.A.
President & Chief Executive Officer

N.G. KNECHT, C.A.
Vice President Finance & Chief Financial Officer

March 23, 2007

Independent Auditors' Report

TO THE SHAREHOLDERS OF
COMPTON PETROLEUM CORPORATION

We have audited the accompanying consolidated balance sheets of Compton Petroleum Corporation as at December 31, 2006 and 2005 and the consolidated statements of earnings, retained earnings, and cash flow for each of the three years in the period ended December 31, 2006. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. Our audit of the financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and 2005 and the results of its operations and cash flow for each of the three years in the period ended December 31, 2006 in accordance with Canadian generally accepted accounting principles.

Canadian generally accepted accounting principles vary in certain significant respects from accounting principles generally accepted in the United States of America. Information relating to the nature and effect of such differences are presented in Note 20 to the consolidated financial statements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 23, 2007, expressed an unqualified opinion on management's assessment of internal controls over financial reporting and an unqualified opinion on the effectiveness of internal controls over financial reporting.

Grant Thornton LLP

Calgary, Canada
March 23, 2007

Grant Thornton LLP
Chartered Accountants

Independent Auditors' Report

We have audited management's assessment, included in the accompanying Management Report that Compton Petroleum Corporation maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or dispositions of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as at December 31, 2006 is fairly stated, in all material respects, based on criteria established in Internal Control – Integrated Framework issued by COSO. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control – Integrated Framework issued by COSO.

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as at December 31, 2006 and 2005 and the consolidated statements of earnings, retained earnings and cash flow for each of the three years in the period ended December 31, 2006 and our report dated March 23, 2007, expressed an unqualified opinion on those financial statements.

Grant Thornton LLP

Calgary, Canada
March 23, 2007

Grant Thornton LLP
Chartered Accountants

Consolidated Balance Sheets

As at December 31 (thousands of dollars),		2006	2005
Current			
Cash		$ 12,232	$ 8,954
Accounts receivable		83,535	122,073
Unrealized risk management gain	*(Note 16a (i))*	22,625	–
Other current assets	*(Note 16b (ii))*	24,513	10,726
Future income taxes	*(Note 15b)*	1,479	2,609
		144,384	144,362
Property and equipment	*(Note 4 and 19)*	1,977,062	1,587,371
Goodwill	*(Note 2)*	7,914	7,914
Deferred financing charges and other	*(Note 8)*	14,144	12,841
Deferred risk management loss	*(Note 16a (ii))*	3,968	5,610
		$2,147,472	$1,758,098
Current			
Accounts payable		$ 141,443	$ 203,869
Unrealized risk management loss	*(Note 16a (i) and (iii))*	4,604	7,758
Future income taxes	*(Note 15b)*	7,269	–
		153,316	211,627
Bank debt	*(Note 5)*	330,000	177,900
Senior term notes	*(Note 6)*	524,385	357,640
Asset retirement obligations	*(Note 10)*	29,791	20,770
Unrealized risk management loss	*(Note 16a (iii))*	6,816	10,201
Future income taxes	*(Note 15b)*	302,690	314,726
Non-controlling interest	*(Note 3)*	66,350	68,898
		1,413,348	1,161,762
Capital stock	*(Note 11b)*	231,992	226,444
Contributed surplus	*(Note 12a)*	16,974	9,173
Retained earnings		485,158	360,719
		734,124	596,336
		$2,147,472	$1,758,098

Commitments and contingent liabilities *(Note 18)*

Subsequent events *(Note 19)*

On behalf of the Board

M.F. Belich, Q.C.
Director

J.A. Thomson, C.A.
Director

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Earnings

Years ended December 31, (thousands of dollars, except per share data)		2006	2005	2004
Revenue				
Oil and natural gas revenues		$ 533,656	$ 557,879	$ 391,659
Royalties		(123,677)	(132,717)	(93,416)
		409,979	425,162	298,243
Expenses				
Operating		95,462	66,802	55,655
Transportation		12,564	10,858	8,595
General and administrative		26,231	21,223	15,215
Interest and finance charges	*(Note 7)*	54,075	34,951	33,733
Tender costs	*(Note 8)*	–	20,750	–
Depletion and depreciation		143,057	105,504	82,554
Foreign exchange (gain)	*(Note 9)*	(891)	(7,353)	(14,631)
Accretion of asset retirement obligations	*(Note 10)*	2,257	1,975	1,670
Stock-based compensation	*(Note 12a and c)*	10,488	5,903	3,410
Risk management (gain) loss	*(Note 16a (iv))*	(63,721)	19,302	8,808
		279,522	279,915	195,009
Earnings before taxes and non-controlling interest		130,457	145,247	103,234
Income taxes	*(Note 15a)*			
Current		44	5,071	2,751
Future		(3,636)	52,317	33,432
		(3,592)	57,388	36,183
Earnings before non-controlling interest		134,049	87,859	67,051
Non-controlling interest	*(Note 3)*	6,623	6,533	3,418
Net earnings		$ 127,426	$ 81,326	$ 63,633
Net earnings per share	*(Note 13)*			
Basic		$ 1.00	$ 0.65	$ 0.54
Diluted		$ 0.95	$ 0.62	$ 0.51

Consolidated Statements of Retained Earnings

Years ended December 31, (thousands of dollars)		2006	2005	2004
Retained earnings, beginning of year		$ 360,719	$ 284,712	$ 224,569
Net earnings		127,426	81,326	63,633
Premium on redemption of shares	(Note 11b)	(2,987)	(5,319)	(3,490)
Retained earnings, end of year		$ 485,158	$ 360,719	$ 284,712

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flow

Years ended December 31, (thousands of dollars)		**2006**	2005	2004
Net earnings		**$ 127,426**	$ 81,326	$ 63,633
Amortization of deferred charges and other		**1,996**	2,190	2,101
Tender costs		**–**	20,750	–
Depletion and depreciation		**143,057**	105,504	82,554
Accretion of asset retirement obligations		**2,257**	1,975	1,670
Unrealized foreign exchange (gain)		**(665)**	(7,808)	(14,652)
Future income taxes		**(3,636)**	52,317	33,432
Unrealized risk management (gain) loss		**(27,522)**	10,171	2,179
Stock-based compensation		**9,121**	5,903	3,410
Asset retirement expenditures		**(2,352)**	(749)	(614)
Non-controlling interest		**6,623**	6,533	3,418
		256,305	278,112	177,131
Change in non-cash working capital	*(Note 17)*	**18,901**	8,441	(12,594)
		275,206	286,553	164,537
Issuance (repayment) of bank debt		**152,100**	(42,100)	43,373
Issuance of senior notes		**174,930**	353,130	–
Issue costs on senior notes		**(3,408)**	(12,670)	–
Redemption of senior notes		**(7,520)**	(199,973)	–
Proceeds from share issuances, net		**4,672**	89,752	3,258
Proceeds from partnership unit issuance		**–**	–	74,343
Distributions to partner		**(9,171)**	(9,172)	(6,114)
Redemption of common shares		**(3,433)**	(6,118)	(4,005)
Change in non-cash working capital	*(Note 17)*	**1,278**	(1,829)	324
		309,448	171,020	111,179
Property and equipment additions		**(490,429)**	(484,213)	(296,676)
Corporate acquisitions	*(Note 2)*	**–**	–	(12,132)
Property acquisitions		**(34,444)**	(28,575)	(20,830)
Property dispositions		**1,350**	–	19,276
Change in non-cash working capital	*(Note 17)*	**(57,853)**	54,101	29,166
		(581,376)	(458,687)	(281,196)
		3,278	(1,114)	(5,480)
beginning of year		**8,954**	10,068	15,548
end of year		**$ 12,232**	$ 8,954	$ 10,068

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

December 31, 2006

(Tabular amounts in thousands of dollars, unless otherwise stated)

1. SIGNIFICANT ACCOUNTING POLICIES

Compton Petroleum Corporation (the "Company" or "Compton") is in the business of the exploration for and production of petroleum and natural gas reserves in the Western Canada Sedimentary Basin.

A) *BASIS OF PRESENTATION*

The consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada within the framework of the accounting policies summarized below. Information prepared in accordance with accounting principles generally accepted in the United States is included in Note 20.

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. The consolidated financial statements also include the accounts of Mazeppa Processing Partnership in accordance with Accounting Guideline 15 ("AcG-15") "*Consolidation of Variable Interest Entities*", as outlined in Note 3.

All amounts are presented in Canadian dollars unless otherwise stated.

B) *MEASUREMENT UNCERTAINTY*

The timely preparation of financial statements requires that Management make estimates and assumptions and use judgment regarding assets, liabilities, revenues, and expenses. Such estimates relate primarily to transactions and events that have not settled as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depletion and depreciation, and amounts used in impairment test calculations are based upon estimates of petroleum and natural gas reserves and future costs to develop those reserves. By their nature, these estimates of reserves, costs, and related future cash flows are subject to uncertainty, and the impact on the consolidated financial statements of future periods could be material.

The calculation of asset retirement obligations include estimates of the ultimate settlement amounts, inflation factors, credit adjusted discount rates, and timing of settlement. The impact of future revisions to these assumptions on the consolidated financial statements of future periods could be material.

The values of pension assets and obligations and the amount of pension costs charged to net earnings depend on certain actuarial and economic assumptions which by their nature are subject to measurement uncertainty.

C) *PROPERTY AND EQUIPMENT*

i) Capitalized costs

The Company follows the full cost method of accounting for its petroleum and natural gas operations within one Canadian cost centre. Under this method all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Costs include lease acquisition costs, geological and geophysical expenses, costs of drilling both producing and non-producing wells, production facilities, future asset retirement costs, and certain general and administrative expenses directly related to exploration and development activities.

Proceeds from the sale of properties are applied against capitalized costs, without any gain or loss being realized, unless such sale would significantly alter the rate of depletion and depreciation.

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs, other than major turnaround costs, are expensed as incurred. Major turnaround costs are included in property and equipment when incurred and charged to depletion and depreciation in the consolidated statement of earnings over the estimated period of time to the next scheduled turnaround.

Depletion and depreciation of property and equipment is provided using the unit-of-production method based upon estimated proved petroleum and natural gas reserves. The costs of significant undeveloped properties are excluded from costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties or impairment has occurred. Estimated future costs to be incurred in developing proved reserves are included and estimated salvage values are excluded in costs subject to depletion. For depletion and depreciation purposes, relative volumes of natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Depreciation of certain midstream facilities is provided for on a straight line basis over 30 years and depreciation of office equipment is provided for on a declining balance basis which range from 20% to 30% per year.

At each reporting period the Company performs an impairment test to determine the recoverability of capitalized costs associated with reserves. An impairment loss is recognized when the carrying amount of a cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves plus the costs of unproved properties. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of the fair value of discounted proved and probable reserves and the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

The Company recognizes the fair value of estimated asset retirement obligations on the consolidated balance sheet when a reasonable estimate of fair value can be made. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as well sites, pipelines, and facilities. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

Asset retirement costs are amortized using the unit-of-production method and are included in depletion and depreciation in the consolidated statement of earnings. Increases in the asset retirement obligations resulting from the passage of time are recorded as accretion of asset retirement obligations in the consolidated statement of earnings.

Actual expenditures incurred are charged against the accumulated obligation.

v) Inventories

Physical inventory held for exploration, development, and operating activities is included in property and equipment and is valued at cost.

D) GOODWILL

Goodwill is recorded on a corporate acquisition when the purchase price is in excess of the fair values assigned to assets acquired and liabilities assumed. Goodwill is not amortized and an impairment test is performed at least annually to evaluate the carrying value. To assess impairment, the fair value of the consolidated entity, excluding the Mazeppa Processing Partnership, is determined and compared to the carrying value. If the fair value is less than the carrying value then a second test is performed to determine the amount of the impairment. Any loss recognized is equal to the difference between the implied fair value and the carrying value of the goodwill.

E) FINANCIAL INSTRUMENTS AND DERIVATIVES

Financial instruments consist mainly of cash, accounts receivable, other current assets, accounts payable, and long-term debt. The Company uses derivative financial instruments for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates, and interest rates as outlined in Note 16. The Company has elected not to designate any of its current risk management activities as accounting hedges and accounts for all derivative financial instruments using the mark-to-market accounting method.

F) JOINT OPERATIONS

Certain petroleum and natural gas activities are conducted jointly with others. These consolidated financial statements reflect only the Company's proportionate interest in such activities.

G) EARNINGS PER SHARE AMOUNTS

The Company uses the treasury stock method to determine the dilutive effect of stock options. This method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price for the period. Basic net earnings per common share are determined by dividing net earnings by the weighted average number of common shares outstanding during the period. Diluted earnings per share are computed by giving effect to the potential dilution that would occur if stock options were exercised.

H) INCOME TAXES

Income taxes are recorded using the liability method of accounting. Future income taxes are calculated based on the difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Changes in income tax rates that are substantively enacted are reflected in the period the change occurs.

I) REVENUE RECOGNITION

Revenue associated with the production and sale of crude oil, natural gas, and natural gas liquids owned by the Company is recognized when title passes to the customer and delivery has taken place. Revenue as reported, represents the Company's share and is presented before royalty payments to governments and other mineral interest owners. Other revenue is recognized in the period that the service is provided to the customer.

J) STOCK-BASED COMPENSATION PLAN

The Company records compensation expense in the consolidated statements of earnings for stock options granted to Directors, Officers, and employees using the fair-value method. Compensation costs are recognized over the vesting period and the fair values are determined using the Black-Scholes option pricing model.

The Company also has an employee stock savings plan. The contributions are recorded as compensation expense as incurred.

K) DEFERRED FINANCING CHARGES

Financing costs related to the issuance of senior term notes are deferred and are amortized over the term of the notes on a straight-line basis. If the notes are retired, in whole or in part, prior to maturity, a pro-rata share of the unamortized balance is expensed in the consolidated statement of earnings.

L) FOREIGN CURRENCY TRANSLATION

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into Canadian dollars at the period-end exchange rate, with any resulting gain or loss recorded in the consolidated statement of earnings.

M) DIVIDEND POLICY

The Company has neither declared nor paid any dividends on its common shares. The Company intends to retain its earnings to finance growth and expand its operations and does not anticipate paying any dividends on its common shares in the foreseeable future.

N) DEFINED BENEFIT PENSION PLAN

The Company accrues for obligations under a defined benefit pension plan and the related costs, net of plan assets for employees of Mazeppa Processing Partnership. The cost of the pension is actuarially determined using the projected benefit method based on length of service and reflects Management's best estimate of expected plan investment performance, salary escalation, and retirement age of employees.

O) RECENT ACCOUNTING PRONOUNCEMENTS

In 2005, the Canadian Institute of Chartered Accountants ("CICA") issued three new accounting standards: Handbook Section 1530, *"Comprehensive Income"*, Handbook Section 3855, *"Financial Instruments - Recognition and Measurement"*, and Handbook Section 3865, *"Hedges"*. The new standards introduce the Consolidated Statement of Comprehensive Income which is used to temporarily provide for gains and losses including foreign currency translation adjustments and other amounts arising from changes in fair value until they are realized and recorded in net earnings. As well, all financial instruments, including derivatives, are to be included in the company's consolidated balance sheet and measured at fair value. In certain situations assets that are classified as held to maturity will continue to be measured at cost. The new standards also include further clarification on the application of hedge accounting which will have no impact on the Company's financial statements which currently reflect mark-to-market accounting for derivative instruments. These new standards are effective for fiscal years beginning on or after October 1, 2006 and early adoption is permitted. The Company has assessed the impact of these new accounting standards on the consolidated financial statements at January 1, 2007 and has determined that:

- The balance in deferred financing charges will no longer be disclosed separately but will be netted against the corresponding senior term notes.
- The presentation of accumulated other comprehensive income will be similar to the presentation of United States accounting principles and reporting included in Note 20.
- The measurement and recording of financial instruments at fair value will not have a material impact on the Company's consolidated financial statements.

In July 2006, the CICA replaced Handbook Section 1506, *"Accounting Changes"* with a new Section 1506, *"Accounting Changes"* to substantially harmonize with International Accounting Standards for the accounting and disclosure of changes in accounting estimates and errors. Under the new standard, accounting changes should be applied retrospectively unless otherwise permitted or where impracticable to determine. In addition, voluntary changes in accounting policy are made only if they result in the financial statements providing reliable and more relevant information. New disclosure is required for changes in accounting policies, changes in accounting estimates and correction of errors. The standard is effective for fiscal years beginning on or after January 1, 2007. The Company does not expect the application of this revised standard to have a material impact on the consolidated financial statements.

In December 2006, the CICA issued two new accounting standards: Handbook Section 3862, *"Financial Instruments - Disclosures"* and Section 3863, *"Financial Instruments – Presentation"*. These new standards will require increased disclosure of financial instruments with particular emphasis on the risks associated with recognized and unrecognized financial instruments and how those risks are managed. The standards are effective for fiscal years beginning on or after October 1, 2007 and the Company is currently assessing the impact on the consolidated financial statements.

In December 2006, the CICA issued a new accounting standard: Handbook Section 1535, *"Capital Disclosures"*, requiring disclosure of information about an entity's capital and the objectives, policies, and processes for managing capital. The standard is effective for fiscal years beginning on or after October 1, 2007 and the Company is currently assessing the impact on the consolidated financial statements.

P) RECLASSIFICATION

Certain amounts disclosed for prior years have been reclassified to conform with current period presentation.

2. BUSINESS COMBINATIONS

On April 12, 2004 and November 15, 2004, respectively, the Company acquired 100% of the issued and outstanding shares of Redwood Energy, Ltd. and Mayfair Energy Ltd. for total cash consideration of $12.1 million plus the assumption of $12.1 million of debt. Both entities were independent exploration and production companies with operations in the Company's core areas.

The business combinations have been accounted for using the purchase method with results of operations included in the consolidated financial statements from the date of acquisition. Goodwill recognized on these transactions amounted to $7.9 million.

During the year ended December 31, 2004, both companies were wound up into Compton Petroleum Corporation and dissolved.

Mazeppa Processing Partnership ("MPP" or "the Partnership") is a limited partnership organized under the laws of the province of Alberta and owns certain midstream facilities, including gas plants and pipelines in Southern Alberta. The Company processes a significant portion of its production from the area through these facilities pursuant to a processing agreement with MPP. The Company does not have an ownership position in MPP, however, the Company, through a management agreement, manages the activities of MPP and is considered to be the primary beneficiary of MPP's operations. Pursuant to AcG-15, these consolidated financial statements include the assets, liabilities, and operations of the Partnership. Equity in the Partnership, attributable to the partners of MPP, is recorded on consolidation as a non-controlling interest and is comprised of the following:

As at December 31,	**2006**	2005
Non-controlling interest, beginning of year	**$ 68,898**	$ 71,537
Earnings attributable to non-controlling interest	**6,623**	6,533
Distributions to limited partner	**(9,171)**	(9,172)
Non-controlling interest, end of year	**$ 66,350**	$ 68,898

Commencing May 1, 2004, pursuant to the terms of a processing agreement between Compton and MPP, Compton pays a monthly fee to MPP for the transportation and processing of natural gas through the MPP owned facilities. The fee is comprised of a fixed base fee of $764 thousand per month plus MPP operating costs, net of third party revenues. These amounts are eliminated from revenues and expenses on consolidation.

The processing agreement has a five year term ending April 1, 2009, at which time Compton may renew the agreement under terms determined at that time or purchase the Partnership units for the predetermined amount of $55 million, deemed to be fair value. In the event that the Company does not renew the processing agreement nor exercise the purchase option, the Limited Partner may dispose of the Partnership units to an independent third party.

MPP has guaranteed payment of certain obligations of its limited partner under a credit agreement between the limited partner and a syndicate of lenders. The maximum liability of the Partnership under the guarantee is limited to amounts due and payable to MPP by the Company pursuant to the processing agreement. The maximum liability at December 31, 2006 was $21.4 million (2005 - $30.6 million) payable over the remaining term of the processing agreement. The Company has determined that its exposure to loss under these arrangements is minimal, if any.

As at December 31, 2006	**Cost**	**Accumulated depletion and depreciation**	**Net**
Exploration and development costs	**$ 1,931,594**	**$ (482,524)**	**$1,449,070**
Production equipment and processing facilities	**582,705**	**(77,863)**	**504,842**
Inventory	**6,818**	**–**	**6,818**
Future asset retirement costs	**17,128**	**(4,906)**	**12,222**
Office equipment	**9,359**	**(5,249)**	**4,110**
	$ 2,547,604	**$ (570,542)**	**$1,977,062**

As at December 31, 2005	Cost	Accumulated depletion and depreciation	Net
Exploration and development costs	$ 1,553,543	$ (366,902)	$1,186,641
Production equipment and processing facilities	436,948	(52,771)	384,177
Inventory	6,469	–	6,469
Future asset retirement costs	10,365	(3,771)	6,594
Office equipment	7,641	(4,151)	3,490
	$ 2,014,966	$ (427,595)	$1,587,371

At December 31, 2006, $9.6 million (2005 - $11.1 million) relating to employee salaries, insurance costs and overhead recoveries determined in accordance with industry procedures were capitalized.

As at December 31, 2006, future capital expenditures of $329.7 million (2005 - $192.9 million, 2004 - $89.1 million), as estimated by independent reserve engineers, relating to the development of proved reserves have been included in costs subject to depletion. The estimated salvage value of production equipment and processing facilities at December 31, 2006 was $120.1 million (2005 - $108.6 million, 2004 - $81.0 million) and was excluded from costs subject to depletion. Undeveloped properties with a cost at December 31, 2006 of $202.9 million (2005 - $251.3 million, 2004 - $187.8 million) included in exploration and development costs, have not been subject to depletion.

The prices used in the evaluation of the carrying value of the Company's reserves for the purposes of the impairment test are:

As at December 31, 2006	Natural gas $ per mcf	Oil $ per bbl	NGL $ per bbl
2007	7.77	63.95	60.66
2008	8.27	65.20	60.10
2009	8.19	62.83	58.37
2010	8.18	60.37	56.69
2011	8.37	58.72	55.21
Approximate % increase thereafter	2.0%	2.0%	2.0%

5. CREDIT FACILITIES

As at December 31,	**2006**	2005
Authorized	**$ 500,000**	$ 289,000
Prime rate	**$ 35,000**	$ 22,900
Bankers' Acceptance	**295,000**	155,000
Utilized	**$ 330,000**	$ 177,900

As at December 31, 2006, the Company had arranged authorized senior credit facilities with a syndicate of banks in the amount of $500 million. Advances under the facilities can be drawn and currently bear interest as follows:

Prime rate plus 0.75%

Bankers' Acceptance rate plus 1.75%

LIBOR rate plus 1.75%

Margins are determined based on the ratio of total consolidated debt to consolidated cash flow. The facilities reach term on July 4, 2007 and, if not renewed, will mature 366 days later on July 5, 2008.

The senior credit facilities are secured by a first fixed and floating charge debenture in the amount of $1.0 billion covering all the Company's assets and undertakings.

As at December 31,	**2006**	2005
Senior term notes		
US$450 million, 7.625% due December 1, 2013	**$ 524,385**	$ 349,770
US$6.75 million, 9.90% due May 15, 2009	**–**	7,870
	$ 524,385	$ 357,640

On April 4, 2006, the Company issued an additional U.S.$150 million 7.625% senior term notes due 2013 under the same terms and conditions as the 7.625% notes outstanding at December 31, 2005. The proceeds from the issue of the notes were used to repay a portion of the debt outstanding under the Company's senior credit facilities. The Company also used a portion of the proceeds to redeem the balance of the U.S.$6.75 million 9.90% senior notes on May 16, 2006, being the first call date, at 104.95%.

In November 2005, the Company and a wholly owned subsidiary of the Company completed a tender offer and consent solicitation to amend the Indenture relating to the 9.9% notes. The Company and a wholly owned subsidiary paid 107.195% plus accrued and unpaid interest for the U.S. 158.25 million 9.9% notes tendered by the note holders. Information related to the tender costs can be found in note 8.

The 7.625% notes are not redeemable by the Company prior to December 1, 2009, except in limited circumstances. After that time, they can be redeemed in whole or part, at the rates indicated below:

December 1, 2009	103.813%
December 1, 2010	101.906%
December 1, 2011 and thereafter	100.000%

The senior term notes are subordinate to the Company's senior credit facilities.

Amounts charged to expense during the year ended are as follows:

Years ended December 31,	**2006**	2005	2004
Interest on bank debt, net	**$ 15,356**	$ 11,520	$ 9,662
Interest on senior term notes	**35,880**	20,912	21,281
Finance charges	**2,839**	2,519	2,790
Total	**$ 54,075**	$ 34,951	$ 33,733

Finance charges include the amortization of deferred charges and other current year expenses.

The effective interest rate on bank debt at December 31, 2006 was 5.6% (2005 - 4.2%).

8. DEFERRED FINANCING C[illegible]

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of deferred financing charges associated with the issue of senior term notes:

As at December 31,		**2006**		2005
Deferred financing charges and other, beginning of year	$	**12,841**	$	9,729
Issue costs on 7.625% Senior Notes		**3,408**		12,670
Pro-rata reduction on repayment of 9.90% Senior Notes		**(293)**		(7,053)
Amortization expense		**(1,905)**		(2,119)
Other		**93**		(386)
Deferred financing charges and other, end of year	$	**14,144**	$	12,841

Costs incurred on the tender for the 9.90% senior term notes in 2005 were as follows:

Year ended December 31,		2005
Premium payment	$	7,814
Consent solicitation fee		5,883
Pro-rata reduction of deferred financing charges on repayment of 9.90% Senior Notes		7,053
Total	$	20,750

The balance of the 9.9% senior notes was purchased in 2006 pursuant to a call option provision and no additional tender costs were incurred.

9. FOREIGN EXCHANG[illegible]

Amounts charged to foreign exchange (gain) loss during the year ended were as follows:

Years ended December 31,		**2006**		2005		2004
Foreign exchange gain on translation of US$ debt	$	**(665)**	$	(7,808)	$	(14,652)
Other foreign exchange (gain) loss		**(226)**		455		21
Total	$	**(891)**	$	(7,353)	$	(14,631)

10. ASSET RETIREMENT OB[illegible]

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligations associated with the retirement of oil and natural gas assets:

As at December 31,		**2006**		2005
Asset retirement obligations, beginning of year	$	**20,770**	$	18,006
Liabilities incurred		**7,031**		5,218
Liabilities settled and disposed		**(267)**		(1,275)
Accretion expense		**2,257**		1,975
Revision of estimates		**–**		(3,154)
Asset retirement obligations, end of year	$	**29,791**	$	20,770

The total undiscounted amount of estimated cash flows required to settle the obligations was $233.0 million (2005 - $185.8 million), which has been discounted using a credit-adjusted risk free rate of 10.6% (2005 - 10.7%). The majority of these obligations are not expected to be settled for several years or decades into the future. Settlements will be funded from general Company resources at the time of retirement and removal.

A) AUTHORIZED

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares, issuable in series.

B) ISSUED AND OUTSTANDING

	2006		2005	
As at December 31,	**Number of Shares (000s)**	**Amount**	Number of Shares (000s)	Amount
Common shares outstanding, beginning of year	**127,263**	**$ 226,444**	117,354	$ 135,526
Shares issued for cash, net	**–**	**–**	7,500	87,294
Shares issued under stock option plan	**1,489**	**5,993**	2,926	4,424
Shares repurchased	**(249)**	**(445)**	(517)	(800)
Common shares outstanding, end of year	**128,503**	**$ 231,992**	127,263	$ 226,444

The Company maintains a Normal Course Issuer Bid program on an annual basis. Under the current program, the Company may purchase for cancellation up to 6,000,000 of its common shares, representing approximately 5.0% of the issued and outstanding common shares at the time the bid received regulatory approval.

During the year, the Company purchased for cancellation 248,900 common shares at an average price of $13.79 per share (2005 - 516,600 common shares at an average price of $11.84 per share) pursuant to the normal course issuer bid. The excess of the purchase price over book value has been charged to retained earnings.

C) SHAREHOLDER RIGHTS PLAN

The Company has a shareholder rights plan (the "Plan") to ensure all shareholders are treated fairly in the event of a take-over offer or other acquisition of control of the Company.

Pursuant to the Plan, the Board of Directors authorized and declared the distribution of one Right in respect of each common share outstanding. In the event that an acquisition of 20% or more of the Company's shares is completed and the acquisition is not a permitted bid, as defined by the Plan, each Right will permit the holder to acquire common shares at a 50% discount to the market price at that time.

A) STOCK OPTION PLAN

The Company has a stock option plan for employees, including Directors and Officers. The exercise price of each option approximated the market price for the common shares on the date the option was granted. Options granted under the plan before June 1, 2003 are generally fully exercisable after four years and expire ten years after the grant date. Options granted under the plan after June 1, 2003 are generally fully exercisable after four years and expire five years after the grant date.

The following tables summarize the information relating to stock options:

As at December 31,	2006 Stock options (000s)	2006 Weighted average exercise price	2005 Stock options (000s)	2005 Weighted average exercise price
Outstanding, beginning of year	**11,446**	**$ 6.13**	11,655	$ 3.51
Granted	**2,228**	**$ 13.99**	2,930	$ 11.89
Exercised	**(1,489)**	**$ 3.14**	(2,926)	$ 1.32
Cancelled	**(574)**	**$ 10.92**	(213)	$ 8.30
Outstanding, end of year	**11,611**	**$ 7.79**	11,446	$ 6.13
Exercisable, end of year	**6,593**	**$ 4.82**	6,219	$ 3.38

The range of exercise prices of stock options outstanding and exercisable at December 31, 2006 is as follows:

	Outstanding Options			**Exercisable Options**	
Range of exercise prices	Number of options outstanding (000s)	Weighted average remaining contractual life (years)	Weighted average exercise price	Number of options outstanding (000s)	Weighted average exercise price
$1.25 - $2.99	1,859	2.2	$ 1.76	1,859	$ 1.76
$3.00 - $3.99	1,318	4.5	$ 3.51	1,242	$ 3.49
$4.00 - $4.99	1,402	5.1	$ 4.28	1,310	$ 4.25
$5.00 - $6.99	972	2.0	$ 5.86	727	$ 5.86
$7.00 - $9.99	1,267	2.4	$ 7.61	696	$ 7.61
$10.00 - $12.99	2,827	3.5	$ 11.64	660	$ 11.64
$13.00 - $18.39	1,966	4.1	$ 14.38	99	$ 13.62
	11,611	3.5	$ 7.79	6,593	$ 4.82

The Company has recorded stock-based compensation expense in the consolidated statement of earnings for stock options granted to employees, Directors, and Officers after January 1, 2003 using the fair value method.

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

Years ended December 31,	**2006**	2005	2004
Weighted average fair value of options granted	**$ 6.90**	$ 5.45	$ 3.70
Risk-free interest rate	**4.0%**	3.6%	3.9%
Expected life (years)	**5.0**	5.0	5.0
Expected volatility	**43.5%**	43.9%	49.6%

The following table presents the reconciliation of contributed surplus with respect to stock-based compensation:

As at December 31,	**2006**	2005
Contributed surplus, beginning of year	**$ 9,173**	$ 3,840
Stock-based compensation expense	**9,121**	5,903
Stock options exercised	**(1,320)**	(570)
Contributed surplus, end of year	**$ 16,974**	$ 9,173

The Company has not recorded stock-based compensation expense in the consolidated statement of earnings related to stock options granted prior to 2003. If the Company had applied the fair value method to options granted prior to 2003, the effect would have been as follows:

Years ended December 31,		**2006**		2005		2004
Reduction in net earnings	**$**	**412**	$	1,007	$	1,545
Reduction in net earnings per common share - basic and diluted	**$**	**0.00**	$	0.01	$	0.01

B) SHARE APPRECIATION RIGHTS PLAN

CICA Handbook section 3870 requires recognition of compensation costs with respect to changes in the intrinsic value for the variable component of fixed share appreciation rights ("SARs"). During the years ended December 31, 2006, 2005 and 2004, there were no significant compensation costs related to the outstanding variable component of these SARs. The liability related to the variable component of these SARs amounts to $1.2 million, which is included in accounts payable as at December 31, 2006 (2005 - $1.4 million). All outstanding SARs having a variable component expire at various times through 2011.

C) EMPLOYEE RETENTION PROGRAM

In recognition of the shortage of qualified personnel that currently exists within the industry, the Company implemented an Employee Retention program in July 2006 for its existing employees, excluding Officers and Directors. Under the program and contingent upon various conditions present as at July 1, 2007, the Company may incur additional compensation costs to a maximum amount of $4.2 million. During the year ended December 31, 2006 $1.4 million has been recognized in stock-based compensation expense as a partial recognition of this potential liability. Any amount payable under the program will be paid on July 1, 2007 at which time the final amount will be fully determinable.

The following table summarizes the common shares used in calculating net earnings per common share:

Years ended December 31, (000s)	**2006**	2005	2004
Weighted average common shares outstanding - basic	**127,820**	125,627	117,244
Effect of stock options	**5,806**	6,040	6,789
Weighted average common shares outstanding - diluted	**133,626**	131,667	124,033

In calculating diluted earnings per common share for the year ended December 31, 2006, the Company excluded 1,537,100 options (2005 - 331,800, 2004 - 288,000) as the exercise price was greater than the average market price of its common shares in those years.

14. DEFINED BENEFIT PENSION PLAN

There are 34 employees of MPP currently enrolled in a co-sponsored, defined benefit pension plan. The Company does not have a pension plan for other employees. Information relating to the MPP retirement plan is outlined below:

As at December 31,		2006		2005
Accrued benefit obligation				
Accrued benefit obligation - beginning of year	$	**7,562**	$	6,110
Current service cost		**368**		284
Interest cost		**387**		372
Benefits paid		**(392)**		(378)
Actuarial (gain) loss		**(208)**		1,174
Accrued benefit obligation - end of year	$	**7,717**	$	7,562
Fair value of plan assets				
Fair value of plan assets - beginning of year	$	**5,839**	$	5,221
Employee contributions		**82**		75
Employer contributions		**439**		308
Benefits paid		**(392)**		(378)
Actual return on plan assets		**667**		613
Fair value of plan assets - end of year	$	**6,635**	$	5,839
Accrued benefit asset				
Funded status - plan assets less than benefit obligation		**(1,082)**		(1,723)
Unamortized net actuarial gain		**414**		891
Unamortized past service costs		**793**		862
Accrued benefit asset, included in deferred financing charges and other	$	**125**	$	30

Economic assumptions used to determine benefit obligation and periodic expense were:

Years ended December 31,	2006	2005
Discount rate	**5.0%**	5.0%
Expected rate of return on assets	**7.0%**	7.0%
Rate of compensation increase	**3.5%**	3.5%
Average remaining service period of covered employees	**16 years**	15 years

Actuarial evaluations are required every three years, the next evaluation being January 1, 2009.

Pension expense, included in MPP operating costs, is as follows:

Years ended December 31,		2006		2005
Current service cost	$	**292**	$	232
Interest on accrued benefit obligation		**387**		372
Interest on assets		**(407)**		(364)
Amortization on past service cost		**69**		69
Amortization of net actuarial loss		**9**		–
Pension expense, included in operating expense	$	**350**	$	309

MPP expects to contribute $437 thousand to the plan in 2007.

A) The following table reconciles income taxes calculated at the Canadian statutory rate with actual income taxes:

Years ended December 31,	**2006**	2005	2004
Earnings before taxes and non-controlling interest	**$ 130,457**	$ 145,247	$ 103,234
Canadian statutory rate	**34.5%**	37.6%	38.6%
Expected income taxes	**$ 45,008**	$ 54,613	$ 39,848
Effect on taxes resulting from:			
Non-deductible Crown charges	**2,145**	15,061	17,611
Resource allowance	**(1,987)**	(11,980)	(13,535)
Non-deductible stock-based compensation	**3,147**	2,221	1,316
Federal capital tax	**–**	1,896	2,526
Effect of tax rate changes	**(49,655)**	(5,764)	(8,359)
Non-taxable portion of capital items	**(115)**	–	(2,831)
Other	**(2,135)**	1,341	(393)
Provision for income taxes	**$ (3,592)**	$ 57,388	$ 36,183
Current			
Income taxes	**$ 44**	$ 3,175	$ 225
Federal capital taxes	**–**	1,896	2,526
Future	**(3,636)**	52,317	33,432
	$ (3,592)	$ 57,388	$ 36,183
Effective tax rate	**(2.8)%**	39.5%	35.0%

A significant portion of the Company's taxable income is generated by a partnership. Income taxes are incurred on the majority of the partnership's taxable income in the year following its inclusion in the Company's consolidated net earnings. Current income tax is dependent upon the amount of capital expenditures incurred and the method of deployment.

During the second quarter of 2006, the Canadian Federal and Alberta governments enacted corporate tax rate reductions.

B) The net future income tax liability is comprised of:

As at December 31,	**2006**	2005
Future income tax liabilities		
Property and equipment in excess of tax values	**$ 229,936**	$ 232,258
Timing of partnership items	**83,328**	93,532
Foreign exchange gain on long-term debt	**8,729**	11,466
Other	**2,591**	–
Future income tax assets		
Attributed Canadian royalty income	**(7,462)**	(8,830)
Asset retirement obligations	**(8,642)**	(6,984)
Other	**–**	(9,325)
Net future income taxes	**$ 308,480**	$ 312,117
Net future income taxes	**$ 308,480**	$ 312,117
Current portion	**(5,790)**	2,609
Non-current future income taxes	**$ 302,690**	$ 314,726

16. FINANCIAL INSTRUMENTS

A) *DERIVATIVE FINANCIAL INSTRUMENTS AND RISK MANAGEMENT ACTIVITIES*

The Company is exposed to risks from fluctuations in commodity prices, interest rates, and Canada/US currency exchange rates. The Company utilizes various derivative financial instruments for non-trading purposes to manage and mitigate its exposure to these risks. Effective January 1, 2004, the Company elected to account for all derivative financial instruments using the mark-to-market method.

Risk management activities during the periods, utilizing derivative instruments, relate to commodity price hedges, foreign currency contracts, and cross currency interest rate swap arrangements and are summarized below:

i) Commodity price hedg

The Company enters into hedge transactions relating to crude oil and natural gas prices to mitigate volatility in commodity prices and the resulting impact on cash flow. The contracts entered into are forward transactions providing the Company with a range of prices on the commodities sold. Outstanding hedge contracts at December 31, 2006 are:

Commodity	Term	Daily Notional Volume	Average Price	Mark-to-Market gain
Natural gas				
Collar	Nov./06 - Mar./07	38,095 mcf	$8.43 - $11.15/mcf	$ 5,818
Collar	Apr./07 - Oct./07	28,571 mcf	$6.74 - $9.28/mcf	3,187
				9,005
Crude Oil				
Collar	Jan./07 - Dec./07	3,000 bbls	US$75.00 - $84.55/bbl	13,620
Unrealized risk management gain				$ 22,625

The following financial instruments were entered into subsequent to December 31, 2006:

Commodity	Term	Daily Notional Volume	Average Price
Natural gas			
Collar	Apr./07 - Oct./07	14,286 mcf	$7.35 - $8.88/mcf

At December 31, 2005 the mark-to-market valuation of commodity contracts resulted in a $3.2 million unrealized risk management loss.

ii) Deferred risk management lc

As at January 1, 2004, the Company elected not to designate any of its risk management activities as accounting hedges and accordingly accounts for all derivative instruments using the mark-to-market method. As a result, on January 1, 2004, the Company recorded a liability and a deferred risk management loss of $10.9 million relating to then outstanding commodity hedges and the interest rate swap. During the year ended December 31, 2006, $1.6 million (2005 - $1.6 million) of the deferred loss was charged to earnings. The remaining balance of $4.0 million at December 31, 2006 (2005 - $5.6 million) relates to the interest rate swap and will be charged to earnings in annual amounts of $1.6 million until eliminated in 2009 upon the termination of the swap contract.

iii) Cross currency interest rate swap

Concurrent with the issuance of 9.90% Senior Notes in 2002, the Company entered into interest rate swap arrangements expiring May 2009 that convert fixed rate U.S. dollar denominated interest obligations into floating rate Canadian dollar denominated interest obligations. On purchase of the majority of the 9.90% Senior Notes in

November 2005, the Company elected not to collapse the cross currency interest rate swap. Accordingly, the swap remains outstanding and at December 31, 2006, the Company valued the liability relating to future unrealized losses on the swap arrangements to be $11.4 million (2005 - $14.8 million) on a mark-to-market basis. The current portion of this amount at December 31, 2006 is $4.6 million (2005 - $4.6 million).

Risk management (gains) and losses recognized during the periods relating to commodity prices, foreign exchange notes and the interest rate swap are summarized below:

Year ended December 31, 2006	**Commodity Contracts**	**Foreign Currency**	**Interest Rate Swap**	**Total**
Unrealized				
Amortization of deferred loss	$ –	$ –	$ 1,642	$ 1,642
Change in fair value	(25,775)	–	(3,389)	(29,164)
	(25,775)	–	(1,747)	(27,522)
Realized				
Cash settlements	(39,217)	(1,405)	4,423	(36,199)
Total (gain) loss	$ (64,992)	$ (1,405)	$ 2,676	$ (63,721)

Year ended December 31, 2005	Commodity Contracts	Foreign Currency	Interest Rate Swap	Total
Unrealized				
Amortization of deferred loss	$ –	$ –	$ 1,642	$ 1,642
Change in fair value	5,136	–	3,393	8,529
	5,136	–	5,035	10,171
Realized				
Cash settlements	9,663	–	(532)	9,131
Total loss	$ 14,799	$ –	$ 4,503	$ 19,302

Year ended December 31, 2004	Commodity Contracts	Foreign Currency	Interest Rate Swap	Total
Unrealized				
Amortization of deferred loss	$ 2,001	$ –	$ 1,642	$ 3,643
Change in fair value	(3,986)	–	2,522	(1,464)
	(1,985)	–	4,164	2,179
Realized				
Cash settlements	9,151	–	(2,522)	6,629
Total loss	$ 7,166	$ –	$ 1,642	$ 8,808

B) OTHER FINANCIAL INSTRUMENTS AND RISK

Accounts receivable include amounts receivable for oil and natural gas sales which are generally made to large credit worthy purchasers and amounts receivable from joint venture partners which are generally recoverable from production. Accordingly, the Company views credit risks on these amounts as low.

The Company is exposed to losses in the event of non-performance by counter-parties to financial instruments. The Company deals with major financial institutions and believes these risks are minimal.

ii) Fair value of financial a

The carrying value of cash, accounts receivable, other current assets, current liabilities, and bank debt approximate fair value. The estimated fair value of senior term notes was $503.4 million as at December 31, 2006 versus the carrying amount of $524.4 million. Other current assets are comprised of prepaid expenses, Crown royalty deposits and marketable securities valued at cost. The fair value of the marketable securities at December 31, 2006 exceeded the cost by $1.3 million.

iii) Foreign currency

The Company is exposed to fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and to a certain extent natural gas prices are based upon reference prices denominated in U.S. dollars, while the majority of the Company's expenses are denominated in Canadian dollars. When appropriate, the Company enters into agreements to fix the exchange rate of Canadian dollars to U.S. dollars in order to manage the risk.

On December 31, 2006, all existing foreign exchange contracts expired and the Company has not entered into any new contracts subsequent to year end.

17. CASH FLOW

Changes in non-cash working capital items increased (decreased) cash as follows:

Years ended December 31,	**2006**	2005	2004
Accounts receivable and other current assets	$ **24,751**	$ (17,371)	$ (20,176)
Accounts payable	**(62,425)**	78,385	39,598
Taxes payable	–	(301)	(2,526)
	$ **(37,674)**	$ 60,713	$ 16,896
Net change in non-cash working capital			
Relating to:			
Operating activities	$ **18,901**	$ 8,441	$ (12,594)
Financing activities	**1,278**	(1,829)	324
Investing activities	**(57,853)**	54,101	29,166
	$ **(37,674)**	$ 60,713	$ 16,896

Amounts paid during the year relating to interest expense and capital taxes were as follows:

Years ended December 31,	**2006**	2005	2004
Interest paid	$ **48,857**	$ 31,444	$ 28,604
Current income taxes paid	$ **14**	$ 4,101	$ 4,952

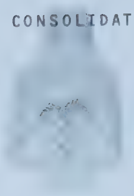
18. COMMITMENTS AND CO

A) *COMMITMENTS*

The Company has committed to certain payments over the next five years, as follows:

	2007	2008	2009	2010	2011
Operating leases	$ 3,737	$ 3,365	$ 2,846	$ –	$ –
Office facilities	3,509	4,923	4,800	4,800	4,800
MPP partnership distributions	9,172	9,172	3,057	–	–
	$ 16,418	$ 17,460	$ 10,703	$ 4,800	$ 4,800

The Company has entered into a lease agreement for new office facilities commencing October 2008. Annual commitments under the lease agreement are approximately $4.8 million per year for the 10 year term.



B) LEGAL PROCEEDINGS

The Company is involved in various legal claims associated with normal operations. These claims, although unresolved at the current time, in management's opinion, are not significant and are not expected to have a material impact on the financial position or results of operations of the Company.

Prior to December 31, 2006, the Company entered into transactions for the sale of certain minor non-core properties, effective at year end. The transactions closed subsequent to year end and net proceeds of $45.9 million from the dispositions were received. The dispositions have been recorded as at the closing dates and have not been recognized in the 2006 financial statements.

[illegible]ND REPORTING

RECONCILIATION OF CONSOLIDATED FINANCIAL STATEMENTS TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conforms to accounting principles generally accepted in the United States of America ("U.S. GAAP"). The significant differences in those principles, as they apply to the Company's statements of earnings, balance sheets, and statements of cash flows, are described below.

RECONCILIATION OF NET EARNINGS UNDER CANADIAN GAAP TO U.S. GAAP:

For the years ended December 31,	**2006**	2005	2004
Net earnings for year, as reported	$ **127,426**	$ 81,326	$ 63,633
Adjustments			
Risk management gain, net (Note e)	**1,166**	1,067	2,236
Depletion and depreciation, net (Note a)	**(7,744)**	650	–
Net earnings – U.S. GAAP	$ **120,848**	$ 83,043	$ 65,869

CONSOLIDATED STATEMENTS OF EARNINGS – U.S. GAAP

For the years ended December 31,	**2006**	2005	2004
Revenue, net of royalties	$ **409,979**	$ 425,162	$ 298,243
Expenses			
Operating	**95,462**	66,802	55,655
Transportation	**12,564**	10,858	8,595
General and administrative	**26,231**	21,223	15,215
Interest and finance charges	**54,075**	55,701	33,733
Depletion and depreciation (Note a)	**153,964**	104,525	82,554
Foreign exchange (gain)	**(891)**	(7,353)	(14,631)
Accretion of asset retirement obligations	**2,257**	1,975	1,670
Stock-based compensation	**10,488**	5,903	3,410
Guarantee (Note h)	**(375)**	(375)	–
Risk management (gain) loss (Note e)	**(65,363)**	17,660	5,165
Earnings before taxes and non-controlling interest	**121,567**	148,243	106,877
Income tax (recovery) expense (Note a, e)	**(6,279)**	58,292	37,590
Non-controlling interest (Note h)	**6,998**	6,908	3,418
Net earnings – U.S. GAAP	$ **120,848**	$ 83,043	$ 65,869
Net earnings per common share – U.S. GAAP			
Basic	$ **0.95**	$ 0.66	$ 0.56
Diluted	$ **0.90**	$ 0.63	$ 0.53

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

For the years ended December 31,	2006	2005	2004
Balance, end of year	$ –	$ –	$ –
Pension plan – adoption of SFAS 158 (Note g)	(893)	–	–
Adjusted balance, end of year	$ (893)	$ –	$ –

CONDENSED CONSOLIDATED BALANCE SHEETS

	2006		2005	
As at December 31,	As reported	U.S. GAAP	As reported	U.S. GAAP
Assets				
Cash	$ 12,232	$ 12,232	$ 8,954	$ 8,954
Other current assets	132,152	132,152	135,408	135,408
Property and equipment (Note a)	1,977,062	1,967,135	1,587,371	1,588,350
Goodwill	7,914	7,914	7,914	7,914
Deferred financing charges and other (Notes f, g)	14,144	12,160	12,841	10,174
Deferred risk management loss (Note e)	3,968	–	5,610	–
	$2,147,472	$2,131,593	$ 1,758,098	$1,750,800
Liabilities and shareholders' equity				
Current liabilities	$ 153,316	$ 153,316	$ 211,627	$ 211,627
Long term debt (Note f)	854,385	852,526	535,540	532,873
Asset retirement obligations	29,791	29,791	20,770	20,770
Unrealized risk management loss	6,816	6,816	10,201	10,201
Guarantee obligation (Note h)	–	873	–	1,248
Unfunded pension liability (Note g)	–	1,082	–	–
Future income taxes (Notes a, c, e)	302,690	297,755	314,726	312,791
Non-controlling interest (Note h)	66,350	65,477	68,898	67,650
	1,413,348	1,407,636	1,161,762	1,157,160
Capital stock (Note c)	231,992	261,979	226,444	256,431
Contributed surplus	16,974	16,974	9,173	9,173
Retained earnings	485,158	445,897	360,719	328,036
Accumulated other comprehensive income (loss) (Note g)	–	(893)	–	–
	734,124	723,957	596,336	593,640
	$2,147,472	$2,131,593	$ 1,758,098	$1,750,800

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOW

For the years ended December 31,	**2006**	2005	2004
Operating activities			
Net earnings	**$ 120,848**	$ 83,043	$ 65,869
Amortization of deferred charges and other	**1,996**	22,940	2,101
Depletion and depreciation	**153,964**	104,525	82,554
Accretion of asset retirement obligations	**2,257**	1,975	1,670
Unrealized foreign exchange (gain)	**(665)**	(7,808)	(14,652)
Future income taxes	**(6,323)**	53,221	34,839
Unrealized risk management (gain) loss	**(29,164)**	8,529	(1,464)
Other	**13,392**	11,687	6,214
Change in non-cash working capital	**(38,952)**	62,542	20,742
Cash from operating activities	**217,353**	340,654	197,873
Cash from financing activities	**309,448**	171,020	111,179
Cash used in investing activities (Note i)	**(523,523)**	(512,788)	(310,362)
Change in cash	**3,278**	(1,114)	(1,310)
Cash, beginning of year	**8,954**	10,068	11,378
Cash, end of year	**$ 12,232**	$ 8,954	$ 10,068

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

The full cost method of accounting for crude oil and natural gas operations under Canadian and U.S. GAAP differ in the following respects.

Under U.S. GAAP, an impairment test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum of the present value, discounted at 10%, of the estimated constant dollar, future net operating revenue from proved reserves plus unimpaired unproved property costs less applicable taxes. Under Canadian GAAP, a similar impairment test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize forecasted pricing to determine whether impairments exist. If an impairment exists, then the amount of the write down is determined using the fair value of reserves. Under SEC regulations, the excess above the ceiling is not expensed if, subsequent to the end of the period, but prior to the release of the financial statements, oil and natural gas prices increase sufficiently such that an excess above the ceiling would have been eliminated if the increased prices were used in the calculation.

The Company has completed an impairment test calculation at December 31, 2006 which indicated an impairment of our oil and natural gas properties of approximately $52 million, net of income tax. However, natural gas prices subsequent to December 31, 2006 have improved sufficiently to eliminate this calculated impairment. As a result, the Company was not required to record a write-down of it's oil and natural gas properties under the full cost method of accounting. Based on spot prices for oil and natural gas as of December 31, 2006, commodity hedges increased the full cost ceiling by $21 million, net of income tax.

Depletion and depreciation on property and equipment is provided using the unit-of-production method under Canadian and U.S. GAAP. Both methods also use proved reserves to determine the rate however, for Canadian GAAP, proved reserves are determined using forecasted prices whereas U.S. GAAP applies constant prices. This reconciliation item resulted in an $10.9 million increase to depletion and depreciation expense for U.S. GAAP purposes during the year ended December 31, 2006 (2005 - $1.0 million reduction).

b) Stock-based compensation

Under Canadian GAAP, compensation costs have been recognized in the consolidated financial statements for stock options granted to employees and directors on or after January 1, 2003. For the effect on periods prior to 2003 of stock-based compensation on the Canadian GAAP financials, which would be the same adjustment under U.S. GAAP, see Note 12.

For the year ended December 31, 2006 the Company adopted SFAS 123 (R) *"Share-based payment"* using the modified prospective approach. Under this amended standard, the intrinsic method of accounting for liability based stock compensation plans, including share appreciation rights, was no longer an alternative. Liability based stock compensation plans are now re-measured at fair value at each reporting period up until the settlement date. The adoption of this amended standard did not have a significant impact on the consolidated financial statements.

c) Future income taxes

Under U.S. GAAP enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted tax rates. The future income tax adjustments included in the reconciliation of net earnings under Canadian GAAP to U.S. GAAP and the balance sheet effects include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

U.S. GAAP requires flow-through shares be recorded at their fair value without any adjustment for the renouncement of the tax deductions and any temporary difference resulting from the renouncement must be recognized in the determination of tax expense in the year incurred.

The cumulative retained earnings adjustment relating to flow-through shares issued prior to December 31, 2003 was $30.0 million.

The net future income tax liability is comprised of:

As at December 31,	**2006**	2005
Future income tax liabilities		
Property and equipment	**$ 227,103**	$ 232,908
Timing of partnership items	**83,328**	93,532
Foreign exchange gain on long-term debt	**8,729**	11,466
Other	**489**	–
Future income tax assets		
Attributed Canadian royalty income	**(7,462)**	(8,830)
Asset retirement obligations	**(8,642)**	(6,984)
Other	**–**	(11,910)
Future income taxes	**$ 303,545**	$ 310,182
Net future income taxes	**$ 303,545**	$ 310,182
Current portion	**(5,790)**	2,609
Non-current future income taxes	**$ 297,755**	$ 312,791

d) Comprehensive income

Statement of Financial Accounting Standards 130, *"Comprehensive Income"*, requires the reporting of comprehensive income in addition to net earnings. Comprehensive income includes net income plus other comprehensive income. Management believes that it has no comprehensive income.

e) Derivative instruments and hedging

On January 1, 2004, the Company adopted under Canadian GAAP, EIC 128 which requires derivatives not designated as hedges to be recorded on the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings. Under the transitional rules, any gain or loss at the implementation date is deferred and recognized into revenue once realized. At January 1, 2004, a deferred loss was recognized in the

amount of $10.9 million. During the year ended December 31, 2006, $1.6 million (2005 - $1.6 million) of the deferred loss was charged to earnings. The remaining balance of $4.0 million (2005 - $5.6 million) relates to the interest rate swap and will be recognized in annual amounts of $1.6 million until eliminated in 2009. Currently, the Company has not designated any of its financial instruments as hedges for accounting purposes under U.S. or Canadian GAAP.

The deferred loss, recognized at January 1, 2004 under the Canadian GAAP transitional provision of EIC 128, has already been recognized in earnings for U.S. GAAP and became a reconciling item at December 31, 2006 and 2005.

Under U.S. GAAP, discounts on long-term debt are classified as a reduction of long-term debt rather than as deferred financing charges. At December 31, 2006 deferred financing charges and senior term notes were reduced by $1.9 million (2005 - $2.7 million).

At December 31, 2006, the Company adopted, for U.S. GAAP purposes SFAS 158, *"Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)"*. These amendments require the Company to recognize the over or under funded status of defined benefit pension plans on the balance sheet as either an asset or liability and to recognize changes in the funding status through other comprehensive income. The transitional provisions, on adoption, require an adjustment to the closing balance of accumulated other comprehensive income. Canadian GAAP currently requires recognition of the accrued benefit or liability and does not require the Company to recognize the funded status of the plan on the balance sheet.

As disclosed in Note 3 to the consolidated financial statements, MPP has guaranteed payment of certain obligations of its limited partner under a credit agreement between the limited partner and a syndicate of lenders. Canadian GAAP only requires disclosure of this type of financial arrangement. U.S. GAAP, under FIN 45 *"Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"*, requires the fair valuation of the guarantee and the inclusion of the liability in the consolidated balance sheets. The offsetting adjustment is reflected as a charge to non-controlling interest.

The guarantee is amortized to earnings, net of the effect on non-controlling interest, over the term of the guarantee.

The consolidated statements of cash flow include under investing activities, changes in working capital for items not affecting cash, such as accounts payable and accounts receivable related to the non-cash elements of property and equipment additions. This presentation is not permitted under U.S. GAAP. The amount for the year ended December 31, 2006 of $(57.9) million (2005 - $54.1 million, 2004 – $29.2 million) has been reallocated to the change in non-cash operating working capital for U.S. GAAP presentation purposes.

j) Receivable and payable amo

As at December 31, (in thousands of Canadian dollars)	**2006**	2005
Accounts receivable includes the following:		
Revenue receivable	**$ 60,720**	$ 91,203
Joint interest receivable	**18,032**	24,482
Other receivables	**4,783**	6,388
	$ 83,535	$ 122,073

As at December 31, (in thousands of Canadian dollars)	**2006**	2005
Accounts payable includes the following:		
Trade payables	**$ 112,624**	$ 161,607
Royalties payable	**17,856**	32,001
Other payables	**10,963**	10,261
	$ 141,443	$ 203,869

k) Recent accountin

As of January 1, 2006, the Company adopted, for U.S. GAAP purposes, SFAS 154 *"Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and SFAS 3"*. The standard required retrospective application of voluntary changes in accounting principles, unless it was impracticable. The adoption of this standard has had no material impact on the Company's consolidated financial statements.

New and revised accounting pronouncements have been evaluated by the Company and it was determined that the following may have a significant impact on the consolidated financial statements:

i) As of January 1, 2007 the Company will be required to adopt, for U.S. GAAP purposes, FASB Interpretation No. 48 *"Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109"*. The interpretation provides clarification and guidance on financial statement recognition and disclosure of uncertain tax positions taken or anticipated in a tax return. The Company has assessed the impact and does not believe that the adoption of this standard will have a material impact on its consolidated financial statements.

ii) As of January 1, 2008, the Company will be required to adopt, for U.S. GAAP purposes, SFAS 157 *"Fair Value Measurements"*. The standard provides a common definition of fair value, expands disclosure about fair value measurements, and establishes a methodology for measuring fair value under U.S. GAAP. The Company is assessing the impact this standard will have on its consolidated financial statements.

Supplemental Oil and Natural Gas Information (unaudited)

A) NET PROVED OIL AND NATURAL GAS RESERVES

The net proved oil and natural gas reserve estimates as at December 31, 2006, 2005 and 2004 set forth below were prepared in accordance with guidelines established by the Securities and Exchange Commission and accordingly were based on existing economic and operating conditions. Oil and natural gas prices in effect as of the respective year ends were used without any escalation except in those instances where the sale was covered by contract, in which case the applicable contract price was used. Operating costs, royalties, and future development costs were based on current costs with no escalation.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present value should not be construed as the current market value of the Company's oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. All of the reserves are located in Canada.

	2006		2005		2004	
Years ended December 31,	**Crude oil & NGLs (mbbls)**	**Natural Gas (mmcf)**	Crude oil & NGLs (mbbls)	Natural Gas (mmcf)	Crude oil & NGLs (mbbls)	Natural Gas (mmcf)
Balance, beginning of year	**29,515**	**455,503**	18,771	359,975	14,542	326,573
Revisions of previous estimates	**(1,130)**	**66,149**	5,550	59,930	2,797	16,547
Extensions, discoveries and other additions	**1,840**	**74,649**	6,498	66,940	3,026	47,713
Acquisitions of minerals in place	**201**	**10,270**	723	5,564	427	9,444
Dispositions of minerals in place	**(229)**	**(12,939)**	–	(56)	(440)	(3,160)
Production	**(2,577)**	**(40,301)**	(2,026)	(36,850)	(1,581)	(37,142)
Balance, end of year	**27,620**	**553,331**	29,516	455,503	18,771	359,975
Proved developed reserves						
Balance, beginning of year	**23,827**	**385,243**	15,481	318,177	10,309	288,899
Balance, end of year	**23,334**	**411,075**	23,827	385,243	15,481	318,177

B) CAPITALIZED COSTS RELATED TO OIL AND NATURAL GAS ACTIVITIES

The aggregate capitalized costs of oil and natural gas activities and costs incurred in oil and natural gas property acquisitions, development, and exploration activities were as follows (excluding MPP and parts inventory):

As at December 31, (in thousands of Canadian dollars)	**2006**	2005
Proved properties	**$2,231,401**	$1,665,455
Unproved properties:		
Acquisition	**131,333**	129,490
Exploration	**108,487**	143,606
Accumulated depletion and depreciation	**(561,961)**	(421,510)
	$1,909,260	$1,517,041

Costs incurred on unproved properties

As at December 31, (in thousands of Canadian dollars)	Cummulative 2006	Includes costs incurred in 2006	2005	2004	Prior Years
Acquisition	$ 131,333	$ 1,843	$ 12,296	$ 13,217	$ 103,977
Exploration	108,487	(35,119)	60,368	13,418	69,820
	$ 239,820	$ (33,276)	$ 72,664	$ 26,635	$ 173,797

Costs incurred

Years ended December 31, (in thousands of Canadian dollars)	2006	2005	2004
Acquisition costs (net of disposition)			
Proved properties	$ 33,094	$ 28,575	$ 12,686
Unproved properties	1,843	12,296	13,217
Development costs			
Development of proved undeveloped reserves	304,316	140,504	60,227
Other	111,773	283,667	136,198
Exploration costs	72,448	46,484	76,648
Total costs incurred	$ 523,474	$ 511,526	$ 298,976

Costs are transferred into the depletion base on an ongoing basis as the undeveloped properties are evaluated and proved reserves are established or impairment determined. Pending determination of proved reserves attributable to the above costs, the Company cannot assess the future impact on the amortization rate.

C) STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN RELATING TO PROVED OIL AND NATURAL GAS RESERVES

The standardized measure of discounted future net cash flows and changes therein relating to proved oil and natural gas reserves ("Standardized Measure") does not purport to present the fair market value of the Company's oil and natural gas properties. An estimate of such value should consider, among other factors, anticipated future prices of oil and natural gas, the probability of recoveries in excess of existing proved reserves and acreage prospects, and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revisions. The computation also excludes values attributable to the Company's midstream interests, referred to in the Financial Statements as Mazeppa Processing Partnership.

Under the Standardized Measure, future cash inflows are estimated by applying year end prices, adjusted for contracts currently in place to deliver production to the estimated future production of year end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on year end costs to determine pre-tax cash inflows. Future taxes are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the Company's tax basis in the associated proved oil and natural gas properties. Tax credits and net operating loss carry forwards are also considered in the future income tax calculation. Future net cash inflows after income taxes are discounted using a 10 percent annual discount rate to arrive at the Standardized Measure.

Years ended December 31, (in thousands of Canadian dollars)	**2006**	2005	2004
Future cash inflows	**$5,253,029**	$6,571,858	$3,160,270
Future production costs	**(1,946,470)**	(1,718,793)	(971,392)
Future development costs	**(339,699)**	(209,901)	(102,557)
Future net cash flows	**2,966,860**	4,643,164	2,086,321
Income taxes	**(519,798)**	(1,344,684)	(539,539)
Total undiscounted future net cash flows	**2,447,062**	3,298,480	1,546,782
10 percent annual discount for estimated timing of cash inflows	**(1,185,942)**	(1,726,975)	(793,904)
Standardized measure of discounted future net cash flows	**$1,261,120**	$1,571,505	$ 752,878

The Company estimates that it will incur $158.2 million in 2007, $110.2 million in 2008 and $35.8 million in 2009 to develop proved undeveloped reserves.

The following table sets forth an analysis of changes in the standardized measure of discounted future net cash flows from proved oil and natural gas reserves:

Years ended December 31, (in thousands of Canadian dollars)	**2006**	2005	2004
Beginning of year	**$1,571,505**	$ 752,878	$ 553,009
Sales of production, net of production costs	**(291,896)**	(336,711)	(226,408)
Net change in sales prices, net of production costs	**(731,330)**	614,690	42,728
Extensions, discoveries and additions	**183,795**	354,186	161,106
Changes in estimated future development costs	**(221,882)**	(135,499)	(54,838)
Development costs incurred during the period which reduced future development costs	**314,251**	353,740	184,053
Revisions in quantity estimates	**(74,504)**	526,474	306,271
Accretion of discount	**215,170**	75,288	75,908
Purchase of reserves	**(23,176)**	(7,749)	(7,749)
Sales of reserves	**47,220**	87	4,416
Net change in income tax	**396,818**	(331,850)	(42,270)
Changes in production rates (timing) and other	**(124,851)**	(294,029)	(243,348)
Standardized measure, end of year	**$1,261,120**	$1,571,505	$ 752,878

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